2005 Annual Report

EPCOR Power L.P.

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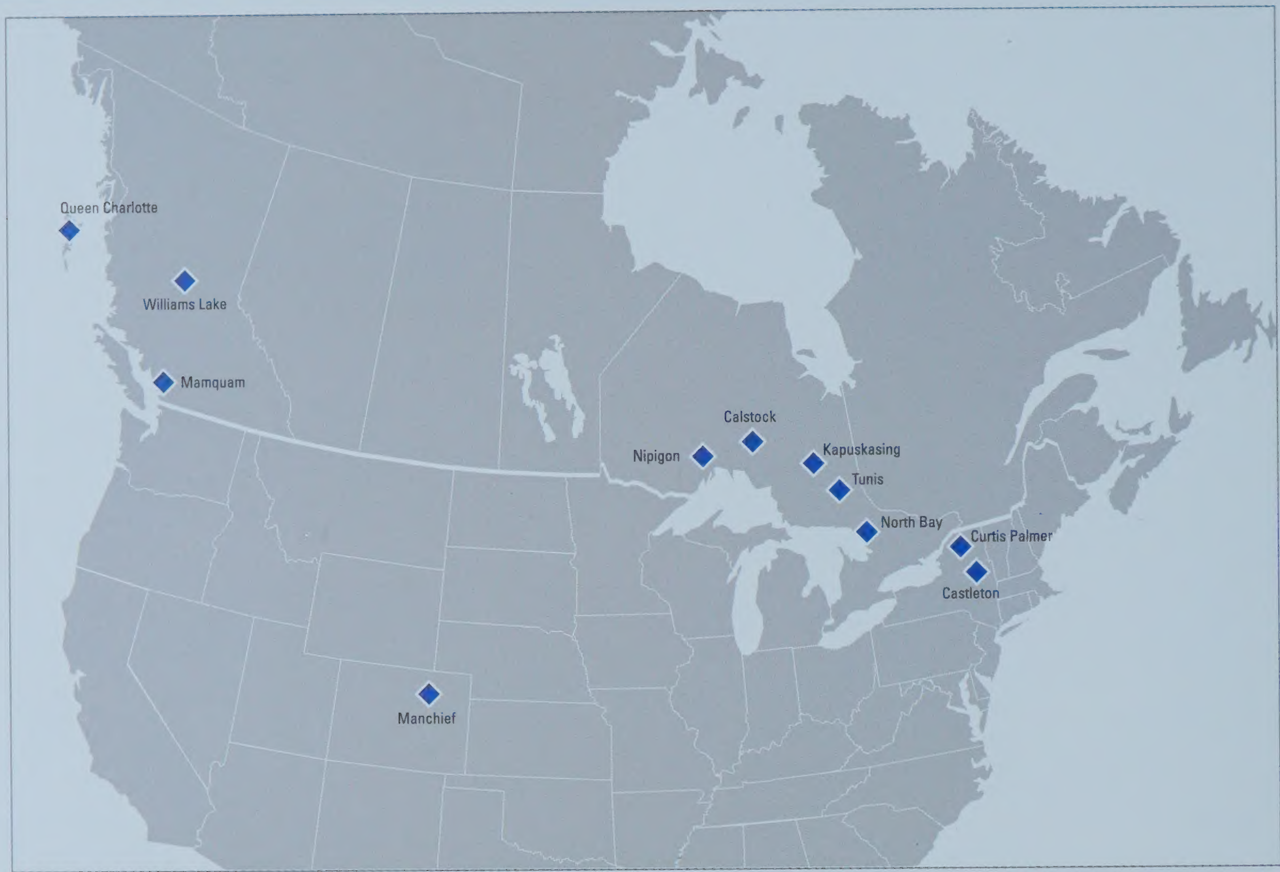
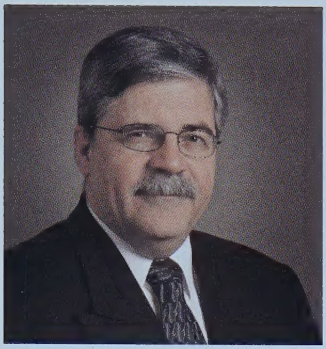


EPCOR Power L.P. owns 11 power plants in Canada and the United States with a total generating capacity of 744 megawatts. These assets offer investors long-term stability and sustainable cash distributions. Driven by a diverse mix of energy sources, including gas, biomass and small hydro, all of the plants operate with long-term power purchase arrangements (PPAs).



President's Message

EPCOR Utilities Inc. was pleased to announce the acquisition of TransCanada Corporation's interest in the TransCanada Power Limited Partnership – re-named EPCOR Power L.P. – in 2005.

The transaction was a defining one for EPCOR, with the Partnership serving as the cornerstone of our power growth strategy. One of EPCOR's core competencies is generating and selling electricity. We are among the largest power producers in Western Canada, and our generation units consistently rank among the nation's most reliable operations.

ALIGNMENT AND INTEGRATION

EPCOR and the Partnership share similar approaches to power generation portfolios. Both recognize the strength of producing electricity from diverse fuel types. And both take a prudent approach to risk management, developing and acquiring reliable generation assets that sell electricity to investment-grade counterparties through long-term power purchase arrangements (PPAs).

These alignments will benefit the Partnership as we focus our efforts on maintaining its position as a premier power investment vehicle.

A key responsibility of the sponsor is to optimize asset value through operations, and to access capital markets when appropriate investment opportunities are developed.

To date, EPCOR has fully integrated the Partnership's operations, and maintained staffing levels at all 11 plants in Canada and the United States. Credit must go to the many employees who planned and implemented a seamless transition in a relatively short timeframe.

In the fourth quarter – the first full quarter under EPCOR management – we achieved a 94% weighted average plant availability. The Partnership generated record quarterly revenues of $81.5 million, with funds generated from operations up 16 per cent from the same period a year ago, primarily due to strong results from the Ontario plants, and high water flows at Curtis Palmer. At our Ontario plants, we were able to take advantage of higher natural gas prices, which resulted in higher enhancement and diversion revenues.

THE STRATEGY FOR SUSTAINABLE CASH FLOW

Having integrated the operation of the Partnership's assets, we are now focused on sustainable cash flow, in part, by adding generation assets that are accretive to cash flows on a per unit basis. This strategy includes three approaches.

First, we will seek out asset acquisitions and test them against rigorous criteria. These criteria include stable and predictable cash flows, contracted revenue from creditworthy counterparties, risk profiles similar to the assets already owned by the L.P., predictable capital expenditures and long operating lives. The L.P. has a right of "first look" on potential acquisitions that meet this criteria.

Second, we will develop new power generation projects that are appropriate for acquisition by the Partnership. EPCOR has successfully developed both large and small projects – from British Columbia's 33 megawatt (MW) Miller Creek small hydro facility to the 450 MW Genesee 3 plant in Alberta. The company also has wind power projects totaling 200 MW under development in Ontario. EPCOR's ability to develop new generation on-time and on-budget offers the Partnership a new channel for growth.

A third approach is for the L.P. to acquire operating assets from EPCOR's existing portfolio where the transaction meets the Partnership's criteria and EPCOR's long-term objectives.

Seeking to ensure the Partnership's interests are aligned with its unitholders, the Board approves all material transactions and agreements of the Partnership. This includes the requirement for approval by a majority of independent Board members on material transactions between the Partnership and EPCOR.

OUTLOOK

Although the Partnership's sponsor has changed, its primary objective remains the same: to provide unitholders with long-term stability and sustainable cash distributions.

Following the close of the transaction on September 1, 2005, both Standard and Poor's and the Dominion Bond Rating Service reaffirmed their strong ratings of the Partnership's senior notes. The Partnership has one of the highest stability ratings in the income trust sector.

In the quarter ending December 31, 2005, the L.P. paid its 34th consecutive cash distribution that either met or exceeded the previous cash distribution. It was also the ninth consecutive quarter where funds generated from operations exceeded cash distributions.

We expect cash flows from existing operations to decline in 2006 relative to 2005 due to a number of factors, such as the temporary step-down in pricing under the Curtis Palmer PPA and the expiry of the Calstock guarantee fee. We do not expect these changes will impact the current distribution to unitholders.

As the manager and operator, we will work to continue the strong performance of our existing plants, and acquire quality power assets whose cash flows are accretive to unitholders.

The strategy we have in place is a sound one, and our interest as a sponsor and the largest unitholder in the Partnership is fully aligned with that of other investors.

We look forward to a year of progress, and to providing unitholders with the long-term stability and sustainable cash distributions they have come to expect from the Partnership.

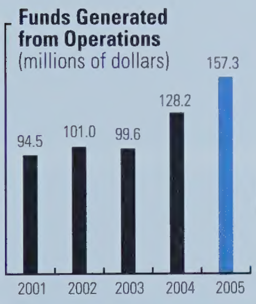
On behalf of the General Partner,

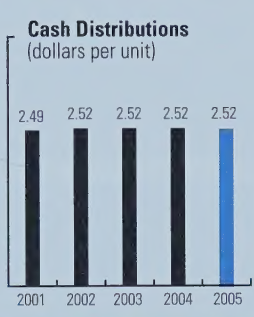
Brian Vaasjo
President

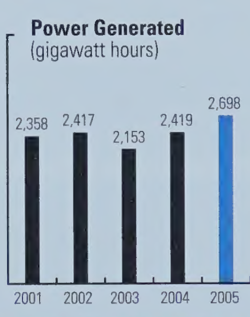
FINANCIAL HIGHLIGHTS

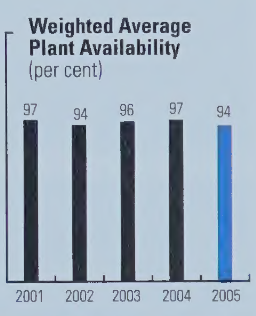
(millions of dollars except per unit amounts)

	2005	2004	% Change
Revenue	**295.7**	241.8	22.3
Net Income	**86.5**	100.7	(14.1)
Per unit ($)	**$1.83**	$2.25	(18.7)
Funds Generated from Operations	**157.3**	128.2	22.7
Per Unit ($)	**$3.32**	$2.87	15.7
Cash Distributions	**119.5**	114.4	4.5
Per Unit ($)	**$2.52**	$2.52	–
Cash Available for Distributions	**142.1**	113.6	25.1
Per Unit ($)	**$3.00**	$2.54	18.1
Capital Expenditures	**14.4**	14.6	(1.4)
Power Generated (GWh)	**2,698**	2,419	11.5
Weighted Average Plant Availability (%)	**94%**	97%	–







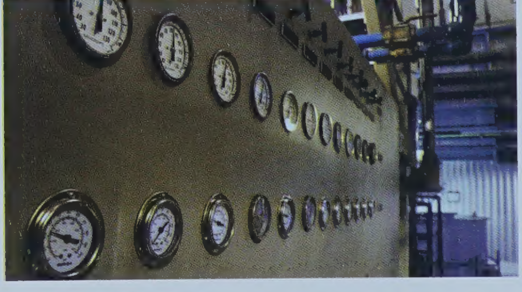


POWER PLANT STATISTICS

	CAPACITY	LOCATION	CONFIGURATION	MAJOR EQUIPMENT*	PARTNERSHIP ACQUISITION	COMMERCIAL OPERATIONS	POWER SALES CONTRACT	FUEL PURCHASE CONTRACT
Calstock	35 MW	Located on a 55-acre site near Hearst, Ontario	Enhanced biomass wood waste generation	1 wood waste boiler; 35 MW steam turbine; 2 HRSGs	1998	2000	20-year term expiring in 2020	Wood waste supply agreements with local mills for 20-year terms expiring in 2019 and 1 mill expiring in 2012
Castleton	64 MW	Located on a 3-acre lease in Castleton-on-Hudson, New York	Combined-cycle gas-fired generation	40 MW gas turbine; 25 MW steam turbine; 1 HRSG	1999	1992	9-year term expiring in 2008	No fuel risk. Partnership pays a fixed demand charge under management agreement.
Curtis Palmer	60 MW	Located on the Hudson River near Corinth, New York	Hydroelectric impoundment and run-of-river	7 turbines	2004	1986***	42-year term expiring in 2027	Not applicable
Kapuskasing	40 MW	Located on a 14-acre site in Kapuskasing, Ontario	Enhanced combined cycle gas fired generation	25 MW gas turbine; 31 MW steam turbine; 3 HRSGs	1997	1997	20-year term expiring in 2017 or delivery of 10,000 GWh	Gas supply agreements for 20-year term expiring in 2016
Mamquam	50 MW	Located on the Mamquam River 50 km north of Vancouver, British Columbia	Hydroelectric run-of-river	2 turbines	2004	1996	30-year term expiring in 2027**	Not applicable
Manchief	300 MW	Located on a 10-acre site near Brush, Colorado	Simple-cycle gas fired generation	2 gas turbines	2004	2000	11-year term expiring in 2012	Not applicable as the the power buyer provides the fuel requirements
Nipigon	40 MW	Located on a 7-acre site near Nipigon, Ontario	Enhanced combined cycle gas fired generation	22 MW gas turbine; 18 MW steam turbine; 3 HRSGs	1997	1992	20-year term expiring in 2012	Gas supply agreements for 21-year terms expiring in 2010 and 2012 respectively
North Bay	40 MW	Located on a 16-acre site near North Bay, Ontario	Enhanced combined cycle gas fired generation	25 MW gas turbine; 31 MW steam turbine; 2 HRSGs	1997	1997	20-year term expiring in 2017	Gas supply agreement with 20-year term expiring in 2016
Queen Charlotte	6 MW	Located on Moresby Island, British Columbia	Hydroelectric reservoir-based	3 turbines	2004	1990	22-year term expiring in 2022	Not applicable
Tunis	43 MW	Located on an 11-acre site near Iroquois Falls, Ontario	Enhanced combined cycle gas fired generation	41 MW gas turbine; 19 MW steam turbine; 3 HRSGs	1998	1995	20-year term expiring in 2014	Gas supply agreements with 15-year term expiring in 2010
Williams Lake	66 MW	Located on a 31-acre site in Williams Lake, British Columbia	Biomass wood waste generation	1 wood waste boiler 66 MW steam turbine	1999	1993	25-year term expiring in 2018	Wood waste supply agreements with local mills for 25 years expiring in 2017 and 1 mill expiring in 2009. Cost recovery mechanism in power sales contract.

* HRSG is a heat recovery steam generator.
** with option exercisable in 2022 and every five years thereafter for power purchaser to buy the facility or extend the contract.
*** these facilities were repowered in 1986.

Management's Discussion and Analysis



This management's discussion and analysis (MD&A) dated March 6, 2006 should be read in conjunction with the accompanying audited consolidated financial statements of EPCOR Power L.P. (the "Partnership") for the years ended December 31, 2005 and 2004. In accordance with its terms of reference, the Audit Committee of the General Partner's Board of Directors review the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors has approved this MD&A.

FORWARD-LOOKING STATEMENTS

Certain information in this MD&A is forward-looking and related to anticipated financial performance, events and strategies. When used in this context, words such as "will", "anticipate", "believe", "plan", "intend", "target", "expect" or similar words suggest future outcomes. By their nature, certain future events are subject to significant risks and uncertainties, which could cause the Partnership's actual results and experience to be materially different than the anticipated results. Such risks and uncertainties include, but are not limited to, the ability of the Partnership to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the availability and price of energy commodities, plant availability, waste heat availability and water flows, regulatory and government decisions, competitive factors in the power industry, the current economic conditions in North America and the performance of contractors and suppliers.

Readers are cautioned not to place undue reliance on forward-looking statements as actual results could differ materially from the plans, expectations, estimates or intentions expressed in the forward-looking statements. Except as required by law, the Partnership disclaims any intention and assumes no obligation to update any forward-looking statement even if new information becomes available, as a result of future events or for any other reason.

STRATEGY

The Partnership's strategic plan continues to be focused on providing stable and sustainable distributions to unitholders. The 2004 acquisitions provide additional sources of cash flows which will primarily be used to fund maintenance capital expenditures and to enhance the stability and sustainability of cash distributions into the future. Where opportunities arise, the Partnership will also seek to grow its asset base by expanding capacity at existing plants and pursuing acquisition opportunities that are accretive on a cash available for distributions per unit basis and meet the Partnership's investment criteria. These criteria include generation assets that have stable and predictable cash flows, contracted with credit worthy counterparties, risk profiles similar to the assets already owned by the Partnership with predictable capital expenditures and long operating lives.

SIGNIFICANT EVENTS

Change in interests in the Partnership

On September 1, 2005, EPCOR Utilities Inc., collectively with its subsidiaries, ("EPCOR") completed its acquisition of the interest in the Partnership held by TransCanada Corporation collectively with its subsidiaries ("TransCanada"). In connection with the close of the transaction the Partnership was renamed from TransCanada Power, L.P. to EPCOR Power L.P. EPCOR's acquisition included approximately 14.5 million units of the Partnership, representing approximately 30.6 per cent of the outstanding units; 100 per cent

ownership of the General Partner of the Partnership; and management and operations agreements governing the ongoing operation of the Partnership's power generation assets.

EPCOR Power Services Ltd., the General Partner of the Partnership, is a wholly-owned subsidiary of EPCOR who has responsibility for management of the Partnership. The Board of Directors of the General Partner declares the cash distributions to the Partnership's unitholders. The General Partner has engaged certain other EPCOR subsidiaries (collectively, the "Manager") to perform management and administrative services on behalf of the Partnership and to operate and maintain the power plants pursuant to management and operations agreements.

2004 plant acquisitions

In 2004, the Partnership acquired four plants, one in New York, one in Colorado and two in British Columbia. The Partnership used a combination of temporary short-term debt, U.S. and Canadian long-term debt and a subscription receipts offering, which were later converted into limited partnership units, to fund these acquisitions. Three of the plants acquired are hydroelectric facilities and one is a natural gas-fired plant.

The Curtis Palmer plant, acquired in April 2004 consists of two separate hydroelectric facilities located on the Hudson River in New York with combined generating capacity of 60 MW.

The Manchief power plant, acquired in April 2004, is a simple-cycle, natural gas-fired power generating facility located near Brush, Colorado with a generating capacity of 300 MW. The plant operates as a peaking facility, generating power primarily during peak power consumption periods.

The Mamquam hydroelectric facility, acquired in July 2004, is a two-unit, 50 MW, run-of-river plant located approximately 50 kilometres north of Vancouver, British Columbia on the Mamquam River. The plant is expected to

POWER GENERATION

	Energy Source	MW
Ontario Plants		
Nipigon [1]	Natural gas/waste heat	40
North Bay [1]	Natural gas/waste heat	40
Kapuskasing [1]	Natural gas/waste heat	40
Tunis [1]	Natural gas/waste heat	43
Calstock [1] [2]	Wood waste/waste heat	35
Williams Lake [2]	Wood waste	66
Mamquam and Queen Charlotte [3]	Water flows	56
Curtis Palmer [3]	Water flows	60
Manchief [4]	Natural gas	300
Castleton [5]	Natural gas	64

(1) The Ontario natural gas-fired plants use a process called enhanced combined cycle generation that uses both natural gas and waste heat as energy sources. These plants and the Calstock plant are located adjacent to TransCanada's Canadian Mainline gas compressor stations.

(2) The Williams Lake and Calstock plants use wood waste from local mills as a source of energy.

(3) The Curtis Palmer, Mamquam and Queen Charlotte hydroelectric facilities rely on water flows to produce electricity.

(4) The Manchief plant is a simple-cycle, natural gas-fired generating facility which is dispatched by the power buyer only during peak demand periods.

(5) The Castleton facility is a combined cycle natural gas plant.

generate approximately 250,000 megawatt hours ("MWh") of electricity per year.

The Queen Charlotte hydroelectric facility, acquired in July 2004, is a three-unit, six MW reservoir-based station located on Moresby Island, B.C. It serves the local community of Sandspit and the surrounding area.

The Partnership now owns eleven power plants and its total generating capacity more than doubled in 2004 to 744 megawatts ("MW") from 328 MW. With the addition of these plants, the Partnership increased the energy supply, counterparty and geographic diversity of its portfolio of assets.

The Partnership's power plants use natural gas, waste heat, wood waste, water flows or a combination of these energy sources to produce electricity.

Each of the Partnership's eleven power plants has long-term power purchase arrangements ("PPAs") with contract expiry dates ranging from 2008 to approximately 2027. Similarly, the Ontario and Williams Lake plants have long-term energy supply contracts. The power buyers under the Manchief and Castleton PPAs provide the plant energy supply under tolling agreements. Curtis Palmer, Mamquam and Queen Charlotte, as hydroelectric plants, do not have energy supply costs but have long-term water licences. The existence of long-term sales contracts combined with long-term energy supply and operating contracts reduces the financial risk to unitholders, minimizes commodity price risk and increases the stability and security of long-term cash flows.

CONSOLIDATED RESULTS

Revenues of $295.7 million for the year ended December 31, 2005 were $53.9 million and $109.9 million higher than for 2004 and 2003, respectively. The increase in 2005 was due to the full year impact of the acquisitions of the Curtis Palmer, Manchief, Mamquam and Queen Charlotte plants in 2004 as well as higher enhancement and diversion revenues at the Ontario plants. Enhancement revenues reflect decisions by the Manager to voluntarily curtail power production in favour of selling the unused natural gas at prevailing market prices. This is normally done in off-peak hours when contracted power prices are lower. Gas diversions occur when the Partnership sells gas in excess of daily plant requirements in situations other than voluntary curtailment such as during planned and unplanned outages. The plants acquired in 2004 contributed revenues of $95.5 million in 2005 and $53.7 million post acquisition in 2004. Ontario plant revenues for the year ended December 31, 2005 were $11.9 million higher than for 2004 primarily due to increased opportunities to optimize results from higher market prices for natural gas through enhancement and diversion revenues. The decline in Castleton revenues from 2003 through 2005 reflects the impact of a weaker U.S. dollar.

The Partnership reported net income of $86.5 million or $1.83 per unit for the year ended December 31, 2005 compared to $100.7 million or $2.25 per unit in 2004 and $64.4 million or $1.64 per unit in 2003. The $14.2 million decrease in net income compared to 2004 was primarily due to lower unrealized foreign exchange gains on translation of the Partnership's U.S. dollar-denominated debt in 2005.

Cash distributions for the year ended December 31, 2005 were $119.5 million compared to $114.4 million and $99.1 million in 2004 and 2003, respectively, reflecting the issue of 8.1 million Partnership units in 2004. Cash distributions per unit remained at $2.52 over the last three years. Cash available for distributions, as defined under Non-GAAP measures, for the year ended December 31, 2005 was $142.1 million compared to $113.6 million and $91.4 million in 2004 and 2003 respectively.

CONSOLIDATED RESULTS-AT-A-GLANCE [1]

Years ended December 31 *(millions of dollars except unit and per unit amounts)*	**2005**	2004	2003
Revenues			
Ontario Plants	**148.8**	136.9	134.0
Williams Lake	**36.5**	35.9	35.5
Mamquam and Queen Charlotte [2]	**15.4**	4.1	–
Curtis Palmer [2]	**53.5**	31.2	–
Manchief [2]	**26.6**	18.4	–
Castleton	**14.9**	15.3	16.3
	295.7	241.8	185.8
Operating Margin [1]			
Ontario Plants	**82.8**	74.4	75.0
Williams Lake	**23.6**	23.9	25.4
Mamquam/Queen Charlotte [2]	**10.7**	3.4	–
Curtis Palmer [2]	**47.1**	26.9	–
Manchief [2]	**20.2**	13.0	–
Castleton	**8.0**	8.2	8.8
	192.4	149.8	109.2
Net Income	**86.5**	100.7	64.4
Per unit	**$1.83**	$2.25	$1.64
Funds generated from operations [1]	**157.3**	128.2	99.6
Per unit	**$3.32**	$2.87	$2.53
Capital Expenditures	**14.4**	14.6	8.2
Long Term Debt	**436.7**	445.2	–
Cash Available for Distributions [1] [3]	**142.1**	113.6	91.4
Per unit	**$3.00**	$2.54	$2.33
Cash Distributions [3]	**119.5**	114.4	99.1
Per unit	**$2.52**	$2.52	$2.52
Total Assets	**1,316.3**	1,339.7	604.7
Weighted Average Units Outstanding (millions)	**47.4**	44.7	39.3

(1) The selected three year annual financial data has been prepared in accordance with Canadian generally accepted accounting principles except for operating margin, funds generated from operations, funds generated from operations per unit, cash available for distributions and cash available for distributions per unit. See "Non-GAAP measures".

(2) From the dates of acquisition: Curtis Palmer and Manchief – April 30, 2004; Mamquam and Queen Charlotte — July 23, 2004.

(3) Cash available for distributions that exceeds cash distributions are used to stabilize future quarterly cash distributions, to finance future capital expenditures and to make discretionary debt repayments.

NON-GAAP MEASURES

The Partnership uses operating margin, funds generated from operations, funds generated from operations per unit, cash available for distributions and cash available for distributions per unit as performance measures. These terms are not defined financial measures according to Canadian generally accepted accounting principles ("GAAP") and they do not have standardized meanings prescribed by GAAP. Therefore, these measures may not be comparable to similar measures presented by other enterprises.

The Partnership uses operating margin to measure the financial performance of plants or groups of plants. A reconciliation from operating margin to net income before tax is as follows:

Years ended December 31 *(millions of dollars)*	**2005**	2004	2003
Operating Margin	**192.4**	149.8	109.2
Deduct:			
Depreciation and amortization	**67.7**	55.0	36.1
Management and administration	**8.9**	6.9	5.5
Foreign exchange (gain)/loss	**(6.4)**	(30.8)	1.7
Financial charges and other	**25.7**	14.1	1.2
Net Income Before Income Tax	**96.5**	104.6	64.7

The Partnership uses funds generated from operations as a performance measure of the Partnership's ability over the long-term to fund unitholder distributions, maintenance capital expenditures and debt repayments. Funds generated from operations of $157.3 million were $29.1 million and $57.7 million higher than the same periods in 2004 and 2003, respectively. These increases were primarily due to the contributions from the plants acquired in 2004. A reconciliation of cash provided by operating activities to funds generated from operations is as follows:

Years ended December 31 *(millions of dollars)*	**2005**	2004	2003
Cash provided by operating activities	**146.7**	143.6	115.8
Increase/(decrease) in operating working capital	**10.6**	(15.4)	(16.2)
Funds generated from operations	**157.3**	128.2	99.6

Funds generated from operations per unit equals funds generated from operations divided by the weighted average number of units outstanding for the respective periods.

The Partnership uses cash available for distributions as a performance measure of the Partnership's ability over the long term to fund unitholder distributions. Cash available for distributions in excess of cash distributions is utilized by the Partnership to stabilize future quarterly cash distributions, to finance future capital expenditures and to make discretionary debt repayments. A reconciliation from cash provided by operating activities to cash available for distributions is as follows:

Years ended December 31	**2005**	2004	2003
(millions of dollars)			
Cash provided by operating activities	**146.7**	143.6	115.8
Increase/(decrease) in operating working capital	**10.6**	(15.4)	(16.2)
Additions to property, plant and equipment	**(14.4)**	(14.6)	(8.2)
Long-term debt repaid	**(0.8)**	–	–
Cash available for distributions	**142.1**	113.6	91.4

Cash available for distributions per unit equals cash available for distributions divided by the weighted average number of units outstanding for the respective periods.

REVENUES AND PLANT OUTPUT

Years ended December 31	2005		2004	
	GWh	*(millions of dollars)*	*GWh*	*(millions of dollars)*
Ontario				
Power	**1,321**	**115.5**	1,372	115.2
Enhancements		**19.9**		11.4
Gas Diversions		**13.4**		10.3
		148.8		136.9
Williams Lake				
Firm energy	**441**	**32.4**	445	32.0
Excess energy/other	**102**	**4.1**	110	3.9
	543	**36.5**	555	35.9
Mamquam and Queen Charlotte (1)	**235**	**15.4**	67	4.1
Curtis Palmer (1)	**353**	**53.5**	198	31.2
Manchief (1)	**83**	**26.6**	42	18.4
Castleton	**163**	**14.9**	185	15.3
	2,698	**295.7**	2,419	241.8
Weighted Average Plant Availability (2)				
Ontario		**97%**		98%
Williams Lake		**94%**		96%
Mamquam and Queen Charlotte (1) (2)		**76%**		76%
Curtis Palmer (1)		**98%**		94%
Manchief (1) (3)		**93%**		100%
Castleton		**97%**		97%
Total weighted average availability		**94%**		97%
Average Price per MWh				
Ontario		**$87**		$84
Williams Lake		**$67**		$65
Mamquam and Queen Charlotte (1)		**$66**		$61
Curtis Palmer (1)		**$152**		$158

(1) From the dates of acquisition: Curtis Palmer and Manchief – April 30, 2004; Mamquam and Queen Charlotte – July 23, 2004

(2) Plant availability represents the percentage of time in the year that the plant is available to generate power, whether actually running or not, and is reduced by planned and unplanned outages

(3) The 300 MW Manchief facility was unavailable for part of the second quarter of 2005 due to a planned maintenance outage

Ontario Plants

All the power output from the Ontario plants is sold to Ontario Electricity Financial Corporation ("OEFC") under long-term power sales contracts with expiry dates ranging from 2012 to 2020. As a result of built-in annual escalators in these contracts, power revenues of $115.5 million for the year ended December 31, 2005, were $0.3 million higher than 2004 and the average price per MWh increased to $87 per MWh in 2005 from $84 per MWh in 2004. Revenues from enhancement and diversion sales in 2005 increased by $11.6 million compared to 2004.

Power output from the Ontario plants for the year ended December 31, 2005 was 51 GWh lower year-over-year although power revenues were slightly higher due to higher contract prices. In 2004, the Partnership entered into a contract with TransCanada to optimize waste heat throughput to the Ontario plants. The Partnership reimburses TransCanada for any incremental fuel gas and administrative costs. In 2005, weighted average plant availability for the Ontario plants was 97 per cent as compared to 98 per cent in 2004.

Williams Lake

Revenues at the Williams Lake plant consist of firm energy sales including cost recovery components, and excess energy sales under the power sales contract with British Columbia Hydro and Power Authority ("BC Hydro") expiring in 2018. The amount of firm energy sold to BC Hydro on an annual basis is fixed at 445,000 MWh, except in years when major overhauls are performed (approximately every five years). Revenues remain constant in major overhaul years and the firm energy commitment to BC Hydro is reduced to 401,000 MWh. Cost recovery components are escalated annually for inflation.

For the year ended December 31, 2005, firm energy revenues of $32.4 million were slightly higher than $32.0 million reported for 2004. The increase in firm revenues was primarily due to increased energy supply cost recoveries in 2005. Excess energy sales for the year ended December 31, 2005 were $4.1 million compared with $3.9 million for 2004. Excess energy sales result when a surplus of energy is generated above the annual firm amount. The price for excess energy is set by an indexed price.

The slight increase in excess energy sales reflects an increase in the market-based price (2005 – $40 per MWh; 2004 – $36 per MWh).

Mamquam and Queen Charlotte

The Mamquam and Queen Charlotte plants have long-term electricity purchase agreements ("EPA") with BC Hydro that expire in 2027 and 2022, respectively. The EPAs consist of a fixed energy component per MWh up to certain output thresholds, an operations and maintenance component adjusted annually for inflation and a reimbursable cost component. All of the electricity generated at the Mamquam plant and substantially all of the electricity generated at the Queen Charlotte plant is sold to BC Hydro. A small amount of electricity from the Queen Charlotte plant is sold to two local industrial customers. These plants contributed $15.4 million in revenues during 2005 and $4.1 million during the period of ownership from July 23, 2004.

Curtis Palmer

Output from the Curtis Palmer plant is sold to Niagara Mohawk Power Corporation ("Niagara Mohawk") under a PPA which expires at the earlier of 2027 or delivery to Niagara Mohawk of a cumulative 10,000,000 MWh of electricity.

The PPA sets out eleven pricing blocks over the contract term for electricity sold to Niagara Mohawk and the price is dependent on the cumulative MWh of electricity delivered. No cumulative MWh thresholds were reached in 2005 and, therefore, pricing under the contract was constant throughout the year. The next pricing threshold was reached in January 2006 when a cumulative total of 3,344,000 MWh was delivered, at which point the price for electricity dropped by approximately 33 per cent. Thereafter, the price increases on average by 10 per cent with each additional 1,000,000 MWh of electricity delivered over the remaining term of the PPA. The Curtis Palmer plant contributed $53.5 million in revenues for the year ended December 31, 2005 and $31.2 million in revenues for the eight months of ownership in 2004.

Manchief

The Manchief plant has two separate tolling agreements covering the sale of capacity and incremental energy to Public Service Company of Colorado ("PSCO"). Both agreements expire in 2012. PSCO controls the dispatch of electricity from the Manchief plant, including start-ups, shut-downs and generation loading levels. Capacity payments are generally unaffected by output levels but vary depending upon changes in plant availability. PSCO pays for incremental energy generated at the plant based upon a fixed price per MWh, escalated annually for inflation. PSCO also pays for turbine start-up fees, heat rate adjustments and gas transportation charges. Revenues were $26.6 million for the year ending December 31, 2005 and for the period of ownership in 2004 the Manchief plant contributed $18.4 million in revenue.

Castleton

Revenues at the Castleton plant, which are adjusted annually for contractual increases, are earned through fixed monthly capacity payments from TransCanada Power Marketing Ltd. ("TCPM") in return for providing the power plant's entire operating capacity. As a result, Castleton revenues are generally unaffected by the amount of electricity generated at the plant, which was down in 2005 compared to 2004 due to reduced dispatch by TCPM. The PPA with TCPM expires in 2008. The Partnership is currently reviewing options for this facility once the PPA expires. Revenues of $14.9 million for the year ended December 31, 2005 were $0.4 million lower than 2004 due to the impact of a weaker U.S. dollar.

COST OF FUEL

Years ended December 31	**2005**	2004
(millions of dollars except average cost per MWh)		
Ontario		
Natural gas	**49.9**	46.6
Waste heat	**1.1**	0.7
Wood waste	**0.3**	0.4
	51.3	47.7
Williams Lake		
Wood waste	**3.6**	3.4
Manchief (1)		
Gas transportation costs	**0.4**	0.3
Castleton		
Natural gas demand charge	**2.3**	2.4
	57.6	53.8
Average cost per MWh		
Ontario	**$39**	$35
Williams Lake	**$7**	$6

(1) From the date of acquisition of April 30, 2004.

Energy supply, which is the Partnership's most significant cost of operations, includes commodity price and transportation costs. Virtually all of the energy for the Ontario and Williams Lake plants is supplied under fixed price, long-term supply agreements with built-in price escalators that generally correspond to price increases under the related PPAs.

Energy supply costs at the Ontario plants for the year ended December 31, 2005 were $51.3 million compared to $47.7 million in 2004. The increase of $3.6 million was primarily due to annual price increases in the gas contracts.

Energy supply costs at the Williams Lake plant were up by $0.2 million to $3.6 million for the year ended December 31, 2005. The variability in energy supply costs for the Williams Lake plant has limited earnings impact as the majority of energy supply costs related to firm energy production is recovered through cost recovery mechanisms in the sales contract with BC Hydro. Energy supply costs at the Castleton plant decreased by $0.1 million due to the impact of a weaker U.S. dollar more than offsetting the inflation increase.

The power buyer under the Manchief and Castleton PPAs is responsible for the gas supply under tolling agreements. For the Castleton plant, the Partnership pays the Manager a fee, escalated annually by an inflation index, for the fixed demand charge while the Partnership is obligated to pay the actual demand charges associated with the transportation of natural gas to the Manchief facility. Curtis Palmer, Mamquam and Queen Charlotte, being hydroelectric plants, do not have energy supply costs.

OPERATING AND MAINTENANCE EXPENSE

Years ended December 31	**2005**	2004
(millions of dollars)		
Ontario	**13.0**	12.8
Williams Lake	**5.6**	5.4
Mamquam and Queen Charlotte [1]	**1.2**	0.6
Curtis Palmer [1]	**1.2**	0.8
Manchief [1]	**3.9**	2.7
Castleton	**3.0**	3.2
	27.9	25.5

(1) From the dates of acquisition: Curtis Palmer and Manchief – April 30, 2004; Mamquam and Queen Charlotte – July 23, 2004.

Operating and maintenance expenses are based on fixed fees, adjusted annually for inflation and are payable to EPCOR (TransCanada prior to September 1, 2005) for the operation and routine maintenance of the plants. The operating and maintenance costs for the Curtis Palmer, Manchief, Mamquam and Queen Charlotte plants reflect the first full year of operations in 2005, which accounts for $2.2 million of the year-over-year increase.

OTHER PLANT OPERATING EXPENSES

Years ended December 31	**2005**	2004
(millions of dollars)		
Property taxes	**10.3**	7.2
Insurance	**4.5**	4.0
Major maintenance	**3.0**	1.5
	17.8	12.7

Other plant operating expenses of $17.8 million for the year ended December 31, 2005 increased by $5.1 million compared to 2004. The increase was primarily due to the additional insurance costs and property taxes attributable to the plants acquired in 2004. Major maintenance expense for the year ended December 31, 2005 increased by $1.5 million due to it being the first full year of operations at the Mamquam and Queen Charlotte plants and increased planned and unplanned work at the Williams Lake plant.

DEPRECIATION AND AMORTIZATION

Years ended December 31 *(millions of dollars)*	**2005**	2004
Plant, property and equipment	**44.2**	40.6
Power purchase arrangements	**23.5**	14.4
	67.7	55.0

Depreciation and amortization expense for the year ended December 31, 2005 was $67.7 million compared to $55.0 million in 2004. The increase in depreciation and amortization expense was due to depreciation and amortization for a full year in 2005 for the plants acquired in 2004.

MANAGEMENT AND ADMINISTRATION

Years ended December 31 *(millions of dollars)*	**2005**	2004
Base fee	**1.2**	1.1
Incentive fee	**2.0**	1.9
Enhancement fee	**2.9**	1.3
General and administrative costs	**2.8**	2.6
	8.9	6.9

Management and administration costs consist of fees paid to EPCOR from September 1, 2005 through December 31, 2005 and to TransCanada prior thereto and general and administrative costs. These costs were $8.9 million for the year ended December 31, 2005 compared to $6.9 million in 2004. Base fees, which are equal to one per cent of the Partnership's annual cash distributions, and incentive fees, which are based on the level of cash distributions to unitholders with reference to pre-determined thresholds, increased slightly reflecting higher aggregate distributions in 2005 as a result of new Partnership units issued during 2004 and the maintenance of constant per unit distributions. Enhancement fees are paid to the Manager for successfully capturing opportunities, on behalf of the Partnership, that either increase revenues or reduce costs. In 2005, the Manager had more opportunity to curtail off-peak power production and sell the natural gas at the Ontario plants and, as a result, enhancement fees increased by $1.6 million. General and administrative costs of $2.8 million were up by $0.2 million compared to 2004 due to higher costs as a result of ownership for a full year in 2005 of the plants acquired in 2004.

FOREIGN EXCHANGE (GAINS)/LOSSES

Years ended December 31	**2005**	2004
(millions of dollars)		
Realized foreign exchange losses	**0.9**	1.1
Unrealized foreign exchange gains on U.S. dollar-denominated debt	**(7.3)**	(31.9)
	(6.4)	(30.8)

The Partnership's foreign exchange gains and losses primarily result from the translation of its U.S. operations. In 2004, the Partnership increased its U.S. operations with the acquisition of the Curtis Palmer and Manchief facilities. The realized foreign exchange loss of $0.9 million and $1.1 million for the years ended December 31, 2005 and December 31, 2004 resulted from holding net monetary assets as the U.S. dollar weakened. The unrealized foreign exchange gain of $7.3 million and $31.9 million for 2005 and 2004, respectively, resulted from the issuance of U.S. dollar-denominated debt in the second quarter of 2004 and the subsequent weakening of the U.S. dollar.

FINANCIAL CHARGES AND OTHER

Years ended December 31	**2005**	2004
(millions of dollars)		
Interest on long-term debt	**25.3**	8.2
Interest on short-term debt	**–**	3.9
Other	**0.4**	2.0
	25.7	14.1

Financial charges and other expenses for the year ended December 31, 2005 were $25.7 million compared to $14.1 million in 2004, representing an increase of $11.6 million. The Partnership initially financed part of its acquisitions in 2004 with temporary debt financing arrangements, these were ultimately replaced by Canadian and U.S. dollar long-term debt.

Interest on long-term debt of $25.3 million for the year ended December 31, 2005, compared to $8.2 million in 2004, included interest on the US$190.0 million long-term debt issued in June 2004, interest on the $210.0 million credit facility placed in November 2004 and interest on the $6.5 million debt assumed on the acquisition of the Mamquam and Queen Charlotte facilities. Interest of $3.9 million on short-term debt for the year ended December 31, 2004 included interest on the Partnership's operating line, acquisition facilities and promissory notes. Other financial charges of $0.4 million for the year ended December 31, 2005, compared to $2.0 million in 2004, primarily consist of amortization of deferred debt issue costs and other interest income and expenses.

LIQUIDITY AND CAPITAL RESOURCES

Cash Distributions

The Partnership makes quarterly cash distributions to Limited Partners in accordance with the Partnership Agreement and subject to Board approval. The cash distributions are made in respect of the quarters ending March, June, September and December in each year to unitholders of record on the last day of such quarters. Payments are made on or about the 30th day after each record date. Distributions are prohibited by certain loan agreement covenants if an uncured default exists. A portion of the cash distributions are taxable to unitholders in the year received. When cash available for distributions exceed cash distributions, the Partnership utilizes the difference to stabilize future quarterly cash distributions, to finance future capital expenditures and to make discretionary debt repayments. In 2005, cash available for distributions of $142.1 million exceeded cash distributions by $22.6 million compared to cash available for distributions in 2004 of $113.6 million which was $0.8 million lower than cash distributions.

Years ended December 31	**2005**	2004
(millions of dollars except per unit amounts)		
Cash available for distributions [1]	**142.1**	113.6
Cash distributions	**119.5**	114.4
Cash available for distributions per unit [1]	**$3.00**	$2.54
Cash distributions per unit	**$2.52**	$2.52
Taxable amount of cash distributions per unit	**$1.46**	$1.29

(1) Non-GAAP measures

Capital Expenditures

Capital expenditures for the power plants are primarily comprised of maintenance capital and additions to, or replacements of, plant equipment required to maintain or increase the power plants' current output capacity. Major overhauls are performed periodically at each of the plants depending on the number of operating hours and type of equipment. Major overhauls at the Ontario plants are performed every 24,000 operating hours or approximately every three years for hot section refurbishments on the gas turbines to approximately 48,000 operating hours or every six years for turbine overhauls. It is expected that the Heat Recovery Steam Generators will require re-tubing approximately once in 20 years. A major overhaul is completed at the Williams Lake plant approximately every five years with the most recent overhaul having occurred in 2003. Similarly, major overhauls are performed at the Castleton plant depending on plant usage.

Major overhauls for the Manchief plant are expected to be performed approximately every 25,000 equivalent operating hours or approximately every five years. Inspections will be performed at the plant on a more regular basis.

Maintenance capital for the hydroelectric facilities is expected to be at longer intervals and will be condition based.

Capital expenditures for the year ended December 31, 2005 were $14.4 million and primarily consisted of a major gas turbine overhaul at each of the Nipigon and Tunis plants. The remaining capital expenditures consisted of plant upgrades, reliability and safety controls and maintenance capital at each of the plants.

The Partnership is committed to funding various capital projects. The total amount of committed capital funding at December 31, 2005 was $2.6 million. Although not committed, the Partnership estimates that average annual maintenance capital requirements for existing facilities will be in the range of 2004 and 2005 expenditures. Significant growth or acquisitions would require additional capital financing.

Financing Activities

At December 31, 2005, the Partnership had $436.7 million of long-term debt outstanding comprised of a $210.0 million credit facility due in 2009, a $5.7 million secured term loan due July 2010 and US$190.0 million senior notes issue due July 2014 (2004 – $445.2 million comprised of the $210.0 million credit facility, the US$190.0 million senior notes and the $6.5 million secured term loan). The Partnership maintains a bank operating line of $50.0 million. At December 31, 2005 and 2004 no balance was outstanding on its operating line. The Partnership's debt to total capitalization ratio as at December 31, 2005 increased slightly to 36 per cent from 35 per cent at the end of 2004. The Partnership was compliant with all of its debt covenants under its long-term debt agreements for the years ended December 31, 2005 and 2004.

In April 2004, the Partnership issued 8,110,000 subscription receipts at a price of $37.00 per unit, for net proceeds of $286.9 million. TransCanada (the former sponsor) purchased 540,000 of the subscription receipts for $20.0 million. The subscription receipts were converted to Partnership units upon the acquisition of the Curtis Palmer and Manchief facilities on April 30, 2004 and TransCanada's partnership interest was reduced from 35.6 per cent to 30.6 per cent. This interest is now held by EPCOR.

In addition to the subscription receipts offering, the acquisition of the Curtis Palmer and Manchief facilities in 2004 was also financed with two promissory notes issued to TransCanada for US$192.6 million.

In June 2004, Curtis Palmer Inc., an indirect wholly-owned subsidiary of the Partnership, issued the US$190.0 million of 5.9 per cent senior notes as part of the financing of the Manchief and Curtis Palmer plant acquisitions. The notes are not registered under the U.S. Securities Act of 1933.

In July 2004, the Partnership funded the acquisition of the Mamquam and Queen Charlotte facilities with a second drawing of $188.0 million under the $500 million acquisition facility. The Partnership assumed $6.5 million of long-term debt as part of the acquisition of the Mamquam and Queen Charlotte plants in July 2004.

In August 2004, the Partnership entered into a $50.0 million extendible, revolving, term operating line of credit with a Canadian chartered bank to be used for general Partnership purposes. The Partnership then used this third party operating line to repay the operating line with TransCanada which was then terminated.

In November 2004, the Partnership arranged $210.0 million of five-year, non amortizing debt through a credit facility with a syndicate of Canadian banks. The proceeds of this credit facility were used to repay the outstanding balance of $188.0 million on the acquisition facility. The remaining $22.0 million was used to reduce the balance on the Partnership's third party operating line. The effective interest rate after including the forward hedging contracts is approximately 5.1 per cent.

In 2005, Standard & Poor's (S&P) and Dominion Bond Rating Service (DBRS) reaffirmed the Partnership's senior note debt ratings of A- and A (low), respectively and also reaffirmed the Partnership's stability ratings of SR-1 and STA-1 (low), respectively.

The A- debt rating by S&P is the third highest rating out of 10 rating categories. The minus sign shows the relative standing within the major rating categories. DBRS' A(low) rating designates the Partnership's debt as being of satisfactory credit quality with the protection of interest and principal still substantial. The "A" rating is DBRS' third highest of 10 categories.

The Partnership has also been assigned stability ratings of SR-1 by S&P, which is the highest rating of seven categories and indicates the Partnership has the highest level of distributable cash generation stability relative to other rated Canadian income funds. The STA-1 (low) stability rating by DBRS is the highest of seven categories in their rating system for income fund stability. DBRS further subcategorizes each rating by the designation of "high", "middle" and "low" to indicate where an entity falls within the rating category.

TRANSACTIONS WITH RELATED PARTIES

Years ended December 31 *(millions of dollars)*	**2005**	2004
Revenues		
Castleton – capacity payments [(1)]	**9.8**	15.3
Ontario – enhancement revenues	**19.9**	11.4
Ontario – gas diversion sales	**13.4**	10.3
Ontario – Calstock guarantee fee [(1)]	**2.1**	3.1
	45.2	40.1
Cost of Energy Supply		
Ontario – gas fuel supply [(1)]	**14.9**	20.9
Ontario – gas transportation [(1)]	**7.5**	12.0
Ontario – waste heat [(1)]	**0.4**	0.7
Castleton – gas demand charge	**2.3**	2.4
	25.1	36.0
Operating and Maintenance Expense	**27.8**	25.5
Management and Administration		
Base fee	**1.2**	1.1
Incentive fee	**2.0**	1.9
Enhancement fee	**2.9**	1.3
	6.1	4.3
Acquisition Fees	**–**	8.7
Interest Expense		
Operating line	**–**	0.9
Promissory notes	**–**	0.7
	–	1.6

(1) These transactions were related party transactions only until September 1, 2005 at which time TransCanada sold its interest in the Partnership to EPCOR.

In operating the Partnership's eleven power plants, the Partnership and EPCOR (and prior to September 1, 2005, TransCanada) engage in a number of related party transactions. These transactions are based on contracts and many of the fees are escalated by inflation. The table above summarizes the amounts included in the calculation of net income for the years ended December 31, 2005 and 2004 (see Note 10 to the consolidated financial statements for further details).

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

At December 31, 2005 the Partnership's future purchase obligations were estimated based on existing contract terms and estimated inflation and expected volumes of waste heat based on historical patterns:

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

Years ended December 31	Note	2006	2007	2008	2009	2010	Later Years
(millions of dollars)							
Gas purchase contracts	(1)	34.5	38.6	43.8	45.9	46.0	299.8
Gas transportation contracts	(2)	12.5	13.2	14.0	14.9	15.0	110.3
Waste heat contracts	(3)	0.8	0.8	0.8	0.9	0.9	5.4
Operating and maintenance expense	(4)	28.4	29.0	29.5	26.9	27.4	215.0
Long-term debt	(5)	0.9	1.0	1.1	211.3	1.4	221.0
Interest payments on long-term debt	(6)	24.3	24.2	24.1	23.9	13.0	52.2
Total		101.4	106.8	113.3	323.8	103.7	903.7

(1) The gas purchase contracts have fixed and variable components. The variable components are based on estimates subject to variability in plant production. These contracts have expiry dates ranging from 2010 to 2016 with built-in escalators.

(2) The gas transportation contracts are based on estimates subject to changes in regulated rates for transportation and have expiry dates ranging from 2010 to 2016

(3) Waste heat contracts continue while the plants are in operation. Prices are escalated yearly by the prior year's CPI.

(4) The operating and maintenance contracts are based on fixed fees escalated annually by inflation and have expiry terms ranging from 2008 to 2018.

(5) Includes principal repayments under the term debt of $5.7 million in aggregate and the principal repayment on the $210.0 million credit facility in 2009 and the U.S.$190.0 million debt in 2014.

(6) Includes interest payments for the term debt of $5.7 million, the $210.0 million credit facility and the U.S.$190.0 million debt

In July 2004, NAL Resources Limited ("NAL") and Devon Canada Corporation ("Devon") commenced actions against the Partnership claiming the gas supply contracts under which NAL and Devon sell gas to the Partnership for its Tunis, Ontario power plant have been frustrated as of January 1, 2003 due to an alleged inability to determine the commodity charge for gas under such agreements. NAL and Devon additionally seek monetary damages based on referenced spot gas prices should the courts uphold their claims.

The Partnership has filed statements of defence and intends to vigorously defend the actions. The final outcome is not determinable and accordingly, no amount has been accrued in the financial statements.

OFF-BALANCE SHEET ARRANGEMENTS

The Partnership uses forward foreign exchange contracts and interest rate swaps to manage its exposure to foreign exchange risk related to U.S. dollar-denominated cash flows from its U.S. plants and future anticipated interest payments on Canadian dollar denominated long-term debt. These contacts represent liquid financial instruments held with major Canadian financial institutions and have a fair value based on market pricing. The forward foreign exchange contracts and interest rate swaps are designated, effective hedges and are therefore not recorded on the balance sheet. Any resultant gains and losses related to these financial instruments are deferred and recognized in the same period and financial statement line as the corresponding hedged transaction. At December 31, 2005, forward foreign exchange contracts with a principal

amount of $93.5 million (2004 – $88.5 million) had a fair value of $13.8 million (2004 – $13.2 million). At December 31, 2005, outstanding interest rate swaps had a negative fair value of $5.2 million (2004 – $6.5 million negative fair value) and a notional principal amount of $200 million (2004 – $200 million).

CRITICAL ACCOUNTING ESTIMATES

Since a determination of many assets, liabilities, revenues and expenses is dependent on future events, the preparation of the Partnership's consolidated financial statements requires the use of estimates and assumptions which are made using careful judgement. The Partnership's most significant accounting estimate relates to its calculation of depreciation and amortization expense.

Useful Lives of Assets

The useful lives of the Partnership's property, plant and equipment and PPA assets are estimated for purposes of determining depreciation and amortization expense, in determining asset retirement obligations and in testing for potential impairment of long-lived assets. The estimated useful lives of assets are determined based on judgement, current facts, past experience, designed physical life, potential technological obsolescence and contract periods.

The Partnership depreciates and amortizes its property, plant, equipment and PPA assets over their estimated useful lives. The Partnership amortizes its power generation plant and equipment, less estimated residual value, on a straight-line basis over its estimated remaining useful life. Other equipment, which includes the cost of major overhauls, is capitalized and amortized over estimated service lives of three to ten years. PPAs are amortized on a straight line basis over the remaining lives of the contracts.

Fair Values

Fair values are estimated for purposes of measuring asset retirement obligations and to measure impairment, if any, of long-lived assets.

Expected demolition, restoration and other related costs to settle the Partnership's asset retirement obligations are estimated and discounted at an appropriate credit-adjusted risk-free rate to determine the fair value of the asset retirement obligations.

Undiscounted cash flows are used to test for asset impairment. If the carrying value of the asset is more than the undiscounted cash flows, an impairment loss is recognized to the extent the carrying value exceeds fair value. Estimates of fair value are based on discounted cash flow techniques employing management's best estimates of future cash flows based on specific assumptions and using an appropriate discount rate.

SIGNIFICANT ACCOUNTING POLICIES

Revenue Recognition

Revenue is recognized when energy is delivered under various long-term contracts. Revenue under the Curtis Palmer PPA is recognized at the lower of (1) the cumulative billable contract price per megawatt hour (MWh) and (2) an amount determined by the MWhs made available during the period multiplied by the average price per MWh over the term of the contract from the date of acquisition. Any excess of the contract price over the average price is recorded as deferred revenue.

Foreign Currency Translation

The Partnership indirectly owns United States subsidiaries, the accounts of which are integrated with those of the Partnership and translated into Canadian dollars using the temporal method. Under this method, monetary assets and liabilities are translated at the exchange rate in effect at the balance sheet date. Non-monetary assets and

liabilities are translated at historic exchange rates. Revenues and expenses are translated at rates in effect at the time of the transactions. The resulting foreign exchange gains and losses are included in the consolidated statements of income.

Derivative Financial Instruments

The Partnership has established a hedging program to manage its exposure to changes in foreign currency exchange rates that result from future anticipated U.S. dollar-denominated cash flows from its U.S. power plants. Net U.S. dollar-denominated cash flows are ultimately converted to Canadian dollars to fund a portion of the distributions to unitholders. The Partnership also hedges future anticipated interest payments on certain Canadian dollar-denominated long-term debt.

The fair values of the forward foreign exchange contracts and interest rate hedges are estimated using period-end market rates. These fair values approximate the amount that the Partnership would receive or pay if these instruments were closed out at the period-end dates. Gains or losses relating to these hedges are recognized in income in the same period and in the same financial statement category as the gains or losses on the corresponding hedged transactions.

A derivative must be designated and effective to be accounted for as a hedge. For cash flow hedges, effectiveness is achieved if the changes in the cash flows of the derivative substantially offset the changes in the cash flows of the hedged position and if the timing of the cash flows is similar. In the event that a derivative does not meet the designation or effectiveness criterion, the gain or loss on the derivative is recognized in income immediately. If a derivative that qualifies as a hedge is settled early, the gain or loss at settlement is deferred and recognized when the gain or loss on the designated transaction is recognized. Premiums paid or received with respect to derivatives that are hedges are deferred and amortized to income over the term of the hedge.

NEW ACCOUNTING STANDARDS IN 2005

The Partnership has adopted accounting policies in accordance with the following new accounting standard:

Consolidation of variable interest entities

The Partnership has identified and evaluated its interests which potentially would be subject to the provisions of the new accounting standard for the consolidation of variable interest entities. The Partnership concluded that it does not have any variable interest entities.

FUTURE ACCOUNTING STANDARDS

Financial instruments, hedges, comprehensive income and equity

New accounting standards for financial instruments (recognition and measurement) and hedges will become effective for interim and annual reporting periods commencing January 1, 2007. The standards address the criteria for recognition of financial instruments on the balance sheet, the measurement of financial instruments and the accounting for related gains and losses. The standards also specify how hedge accounting is applied to qualifying transactions and what the appropriate disclosures are. The standards are intended to harmonize Canadian accounting principles for these items with international accounting standards.

The new standards introduce the reporting concept of comprehensive income which will modify the reporting of gains and losses not included in net income, an example being unrealized gains/losses on derivatives used in cash flow hedges. These gains/losses will be included in other comprehensive income. This change in accounting standard is not expected to have a material impact to consolidated net income of the Partnership.

Non-monetary transactions

In June 2005, the CICA issued new Section 3831 – Non-monetary transactions. This new section requires all non-monetary transactions to be measured at fair value unless certain exceptions are met. Commercial substance replaces culmination of the earnings process as the test for fair value measurement. A transaction is deemed to have commercial substance if it causes an identifiable, measurable change in the economic circumstances of the entity. Commercial substance is a function of the cash flows expected by the reporting entity. It applies to non-monetary transactions initiated in periods beginning on or after January 1, 2006. The Partnership does not expect application of this new standard to have a material effect on its consolidated financial statements.

Accounting and financial reporting standards

In January 2005, the Accounting Standards Board (AcSB) announced that it had ratified a new strategic plan whereby the AcSB will move to a single set of globally accepted high level standards over an expected five-year period. For public enterprises, Canadian GAAP will be replaced by International Financial Reporting Standards (IFRS). As they currently exist, Canadian GAAP and IFRS overlap to a great extent but there are some differences that could be significant. The impact to the Partnership cannot be determined until detailed convergence plans are in place.

DISCLOSURE CONTROLS AND PROCEDURES

In conformance with the Canadian Securities Administrators Multilateral Instrument 52-109, the General Partner has filed certificates signed by the President and the Chief Financial Officer that, among other things, deal with the matter of disclosure controls and procedures.

Management has evaluated the design and effectiveness of the Partnership's disclosure controls and procedures as of December 31, 2005, and based on its evaluation has concluded that these are appropriately designed and operating effectively.

The evaluation took into consideration the Partnership's Disclosure Policy, the sub-certification process that has been implemented, and the functioning of its Disclosure Committee. In addition, the evaluation covered the Partnership's processes, systems and capabilities relating to public disclosures, and the identification and communication of material information.

BUSINESS RISKS

The Partnership operates assets under long-term power sales and energy supply contracts. These factors, combined with an excellent ongoing maintenance program, minimize exposures to operational risk and commodity price fluctuations. The most significant risks to the Partnership are those noted below.

Operational Risk

The Partnership's plant operations are susceptible to outages due to equipment failure, which could make plants unavailable to provide service. Plant personnel have developed procedures to minimize the plant downtime required for both scheduled and unscheduled maintenance. The Partnership's maintenance practices are supported by the maintenance of an inventory of strategic spare parts, which can reduce downtime considerably in the event of failure. Strict safety standards are in place at all plants. In addition, the Partnership has adequate insurance to cover equipment breakdown and business interruption. The Partnership's combination of strong operating history and preventative maintenance programs has minimized the impact to the Partnership of significant increases in power plant insurance premiums that have been experienced throughout the power industry in recent years.

PPA Contract Expiry Risk

The Partnership's eleven plants have PPAs that expire between 2008 and 2027. In order to stabilize future cash flows, the Partnership will seek to re-contract its existing plants under new or extended PPAs and acquire new plants that meet its investment criteria. The commercial environment for North American power generation is very competitive and therefore there is no assurance that the Partnership will be successful in re-contracting its existing plants or acquiring new plants.

Commodity Price Risk

The risks associated with the uncertainty of the competitive marketplace, especially the volatility in market prices for electricity, have been managed by the fixed-price, long-term power sales contracts in place with five investment grade power buyers – OEFC, BC Hydro, TransCanada, Niagara Mohawk and PSCO. In addition, the risks associated with the volatility of market prices for natural gas have been managed by fixed-price long-term contracts for the supply of substantially all the natural gas requirements of the Partnership's gas-fired plants. For the Tunis plant, the Partnership is exposed to commodity price risk on its natural gas purchases beginning in 2010 when its energy supply agreement ends prior to the expiry of the OEFC PPA in 2014. Similar exposures exist for shorter periods of time for the Nipigon plant beginning in 2010 and the Kapuskasing and North Bay plants beginning in 2016. Natural gas prices also impact the ability of the Partnership to earn enhancement revenue and diversion sales from the curtailment of electricity production in favour of selling the unused natural gas at prevailing market prices. As previously discussed under Contractual Obligations and Contingencies, the Partnership also has commodity risk associated with its Tunis facility if it is unable to successfully defend its position in litigation with NAL and Devon.

While not traded on the market as a commodity, the wood waste required to fuel the Partnership's two biomass wood waste plants is secured by fixed-price long-term contracts to manage price risk and supply risk.

Waste Heat Supply Risk

The Partnership's Ontario natural gas-fired plants also generate electricity from the waste heat gases of adjoining natural gas compressor stations owned by TransCanada, which is now an unrelated party. Supply of the waste heat gases is secured under long-term contracts; however the availability of the waste heat gases vary depending on the output of the compressor stations. In addition, the availability of waste heat gases is also dependent on the compressor stations remaining in use and able to supply the waste heat gases.

Hydrology Risk

Performance of the Partnership's hydroelectric facilities is partly dependent upon the availability of water. Variances in water flows are caused by non-controllable weather related factors affecting precipitation and could result in volatility of hydroelectric plant revenues. In addition, the Partnership's hydroelectric facilities are exposed to potential dam failure, which could also effect water flows and have an impact on revenues from the associated plants.

Government Risk

The Partnership is subject to risks associated with changes in federal, provincial, state or local laws, regulations and permitting requirements. It is not possible to predict changes in laws or regulations that could impact the Partnership's operations, income tax status or ability to renew permits as required. In September of 2005, the Federal Department of Finance initiated a consultation process on the taxation status of income trusts and other flow-through entities like the Partnership. Although the consultation process was

terminated in November 2005, there is the possibility that the taxation of flow-through entities could be revisited in the future. The Partnership monitors the development of any potential changes in laws or regulations in order to manage the risks by proactively planning for any changes and working with governments and regulators to mitigate issues.

Environment Risk

The Partnership's operations are subject to federal, provincial, state and local environmental laws, regulations and guidelines. If the Partnership fails to comply with environmental requirements, regulators could impose penalties and fines on the Partnership or curtail its operations. If environmental laws, regulations and guidelines change, the Partnership may incur unforeseen costs of compliance or may be unable to comply with more stringent standards causing the Partnership to close facilities.

Credit Risk

The Partnership has exposure to credit risk associated with counterparty default under the Partnership's power sales contracts and energy supply agreements and foreign currency hedges. Credit risk is associated with the ability of counterparties to satisfy their contractual obligations to the Partnership, including payment and performance. Credit risk is managed by making appropriate credit assessments of counterparties on an ongoing basis, dealing with creditworthy counterparties, diversifying the risk by using several counterparties and where appropriate and contractually allowed, requiring the counterparty to provide appropriate security.

Foreign Exchange and Interest Rate Risk Management

The Partnership owns and operates three facilities in the U.S. and has borrowings outstanding that are denominated in U.S. dollars and accordingly, the associated net cash flows are subject to foreign currency gains and losses based on changes in the U.S. – Canadian dollar exchange rate.

The Partnership manages the foreign exchange risk of its future anticipated U.S. dollar-denominated cash flows from its U.S. plants through the use of forward foreign exchange contracts for periods up to six years. At December 31, 2005, US$93.5 million or approximately one half of future net cash flows had been economically hedged for 2006 to 2011 at a weighted average exchange rate of 1.30. By year, the amounts hedged and average rates were as follows.

(millions of U.S. dollars except average rate)	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Forward foreign exchange sales	25.5	14.5	20.0	7.0	11.5	15.0
Average rate	1.33	1.40	1.35	1.21	1.19	1.18

The Partnership enters into forward interest rate swaps to fix future anticipated interest payments on its Canadian credit facility. As at December 31, 2005, quarterly interest payments on $200.0 million of principal amount of debt have been hedged resulting in an effective interest rate after including the hedging contracts of approximately 5.1 per cent until 2009.

Conflict of Interest Risk

Conflicts of interest between the Partnership and EPCOR may result in decisions being made which are not in the best interest of the Partnership. Management and the Board of Directors have procedures in place which seek to ensure any conflict which surfaces between the Partnership and EPCOR is appropriately addressed. This includes the requirement for approval by a majority of independent board members of transactions between the Partnership and EPCOR.

General Economic Conditions and Business Environment

Changes in general economic conditions in the markets within which the Partnership operates impact product demand, revenue, operating costs, and credit and counterparty risk, as well as the timing and amount of capital expenditures made by the Partnership. Changes in general economic conditions may also affect the Partnership's financing costs and access to capital markets. Moreover, the Partnership is subject to changes to policies, statutes and regulations, as well as technological change, that could alter the business environment in which the Partnership operates. Such changes could reduce the ability of the Partnership to compete or reduce the profitability of its business. The Partnership's ability to mitigate these risks is dependent, to some degree, on EPCOR's ability, as the manager, to anticipate such risks and, where possible, to develop appropriate mitigation plans.

There is no assurance that risk management steps taken will avoid future loss due to the occurrence of the above described or unforeseen risks.

OUTLOOK

The Partnership's primary goal is to provide unitholders with stable and sustainable cash distributions. The Partnership will endeavour to accomplish this by an ongoing commitment to operational excellence, capitalizing on further earnings enhancements where possible, as well as through plant expansions and acquisitions of new generating assets in Canada and the U.S.

Funds generated from operations in 2006 are expected to decline relative to 2005 due to the October 2005 expiry of the Calstock guarantee fee of approximately $2.5 million annually and a step-down in pricing of approximately 33 per cent under the Curtis Palmer PPA beginning in the first quarter of 2006. The price changes at Curtis Palmer over the remainder of the contract are step increases with the first one at eighteen per cent currently estimated to take effect in 2009. Output and revenue from the Curtis Palmer facility was positively impacted in 2005 from water flows that were above long- term historic averages for the Hudson River. Enhancement revenues and gas diversion sales will vary based on a number of factors, the most significant of which is natural gas prices which increased dramatically in the last half of 2005. The level of waste heat energy at the Ontario plants provided by TransCanada's adjacent compressor stations operating on the TransCanada's Canadian Mainline is dependent on the amount of natural gas throughput on the pipeline. In 2005 power produced by waste heat contributed approximately 20 per cent of power revenues at the Ontario plants. As described in Note 16 of the consolidated financial statements, the Partnership reached agreement with OEFC on the Direct Customer Rate (DCR) used to index the price of power in the PPAs. The settlement will have a positive cash and net income impact of approximately $8 million and will be recorded in the first quarter of 2006. Maintenance capital spending is expected to be slightly lower in 2006 than it has averaged in 2004 and 2005.

Based on the Partnership's 2006 operating and capital plan and taking into consideration the above noted factors, management estimates that 2006 cash available for distributions will exceed recent annual cash distributions of $2.52 per unit.

SELECTED QUARTERLY AND ANNUAL CONSOLIDATED FINANCIAL DATA

	2005				
Three months ended	**Mar. 31**	**Jun. 30**	**Sep. 30**	**Dec. 31**	**Total**
(millions of dollars except per unit amounts) (unaudited)					
Revenues	**74.5**	**72.3**	**67.4**	**81.5**	**295.7**
Cost of Fuel	**14.0**	**14.5**	**13.6**	**15.5**	**57.6**
Operating and Maintenance Expense	**7.0**	**7.0**	**7.0**	**6.9**	**27.9**
Other Plant Operating Expenses	**3.9**	**4.2**	**4.2**	**5.5**	**17.8**
	49.6	**46.6**	**42.6**	**53.6**	**192.4**
Other Costs					
Depreciation and amortization	**16.5**	**16.5**	**16.5**	**18.2**	**67.7**
Management and administration	**1.8**	**2.2**	**2.4**	**2.5**	**8.9**
Foreign exchange (gains) losses	**1.3**	**2.8**	**(11.3)**	**0.8**	**(6.4)**
Financial charges and other	**6.4**	**6.3**	**6.2**	**6.8**	**25.7**
	26.0	**27.8**	**13.8**	**28.3**	**95.9**
Net Income before Income Tax	**23.6**	**18.8**	**28.8**	**25.3**	**96.5**
Income Taxes	**1.8**	**3.3**	**0.8**	**4.1**	**10.0**
Net Income	**21.8**	**15.5**	**28.0**	**21.2**	**86.5**
Net Income Per Unit	**$0.46**	**$0.33**	**$0.59**	**$0.45**	**$1.83**
Cash Distributions	**29.9**	**29.9**	**29.9**	**29.9**	**119.5**
Cash Distributions Per Unit	**$0.63**	**$0.63**	**$0.63**	**$0.63**	**$2.52**

	2004				
Three months ended	Mar. 31	Jun. 30	Sep. 30	Dec. 31	Total
(millions of dollars except per unit amounts) (unaudited)					
Revenues	51.6	57.8	63.3	69.1	241.8
Cost of Fuel	13.5	14.0	12.9	13.4	53.8
Operating and Maintenance Expense	5.4	6.3	6.9	6.9	25.5
Other Plant Operating Expenses	1.6	4.0	3.7	3.4	12.7
	31.1	33.5	39.8	45.4	149.8
Other Costs					
Depreciation and amortization	9.2	13.8	16.5	15.5	55.0
Management and administration	1.6	1.4	1.9	2.0	6.9
Foreign exchange gains	(0.2)	(5.9)	(14.2)	(10.5)	(30.8)
Financial charges and other	0.3	1.6	5.3	6.9	14.1
	10.9	10.9	9.5	13.9	45.2
Net Income before Income Tax	20.2	22.6	30.3	31.5	104.6
Income Taxes	0.1	1.3	1.2	1.3	3.9
Net Income	20.1	21.3	29.1	30.2	100.7
Net Income Per Unit	$0.51	$0.48	$0.61	$0.65	$2.25
Cash Distributions	24.8	29.8	29.9	29.9	114.4
Cash Distributions Per Unit	$0.63	$0.63	$0.63	$0.63	$2.52

The Partnership's Selected Quarterly and Annual Consolidated Financial Data, which has been prepared in accordance with Canadian GAAP, is set out on page 30. Under the power sales contracts for the Ontario plants, the Partnership receives higher per MWh prices in the winter months (October to March) and lower prices in the summer months (April to September). The lower summer prices reduce the threshold for economic curtailments thereby increasing the profitability of enhancements, gas prices being equal. Contributions from the Williams Lake plant are usually lower in the fourth quarter once the annual firm energy requirements are met and the plant is only producing lower-priced excess energy. Revenues from the hydroelectric facilities are anticipated to be higher in the spring months due to seasonally higher water flows. Results for the year ended December 31, 2005 were indicative of these trends for the first nine months of the year. The last quarter of 2005 had unseasonably high water flows at the Curtis Palmer hydroelectric facility and enhancement and diversion revenues at the Ontario plants increased due to higher natural gas prices.

In the second quarter of 2004, the Partnership acquired the Curtis Palmer and Manchief plants resulting in increased revenues, net income and funds generated from operations. The Partnership also issued U.S. dollar-denominated debt in the second quarter of 2004. This resulted in unrealized foreign exchange gains in the second, third and fourth quarter of 2004 and the third quarter of 2005 and losses in the first, second and fourth quarters of 2005 due to fluctuations in the U.S. dollar. In the third quarter of 2004, the Partnership acquired the Mamquam and Queen Charlotte facilities resulting in further increases to revenues, net income and funds generated from operations.

SELECTED QUARTERLY AND ANNUAL UNIT TRADING INFORMATION (EP.UN)

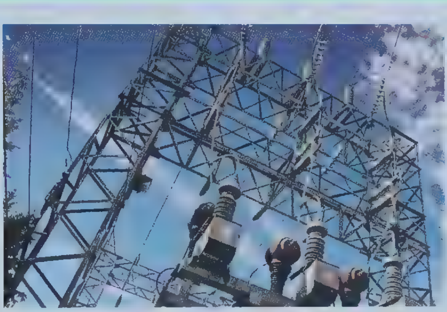
	2005				
Three months ended	**Mar. 31**	**Jun. 30**	**Sep. 30**	**Dec. 31**	**Annual**
(unaudited)					
Unit Price					
High	**$35.90**	**$37.06**	**$37.47**	**$37.00**	**$37.47**
Low	**$31.60**	**$33.15**	**$34.75**	**$29.41**	**$29.41**
Close	**$33.60**	**$36.60**	**$35.99**	**$35.25**	**$35.25**
Volume traded (millions)	**3.5**	**3.7**	**3.7**	**5.4**	**16.3**

	2004				
Three months ended	Mar. 31	Jun. 30	Sep. 30	Dec. 31	Annual
(unaudited)					
Unit Price					
High	$38.00	$36.85	$34.74	$36.00	$38.00
Low	$35.16	$29.62	$31.00	$32.10	$29.62
Close	$36.85	$31.29	$33.40	$35.50	$35.50
Volume traded (millions)	2.6	5.8	4.5	2.9	15.8

ADDITIONAL INFORMATION

Additional information relating to EPCOR Power L.P. including the Partnership's Annual Information Form (AIF) and continuous disclosure documents are available on SEDAR at www.sedar.com.

Consolidated Financial Statements



MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The accompanying consolidated financial statements of EPCOR Power L.P. are the responsibility of management of the General Partner and have been approved by its Board of Directors. In management's opinion, the consolidated financial statements have been prepared within reasonable limits of materiality in accordance with Canadian generally accepted accounting principles. The preparation of financial statements necessarily requires judgment and estimation when events affecting the current year depend on determinations to be made in the future. Management has exercised careful judgment where estimates were required, and these consolidated financial statements reflect all information available to March 6, 2006. Financial information presented elsewhere in this annual report is consistent with that in the consolidated financial statements.

To discharge its responsibility for financial reporting, management maintains systems of internal controls designed to provide reasonable assurance that the Partnership's assets are safeguarded, that transactions are properly authorized and that reliable financial information is relevant, accurate and available on a timely basis. The internal control systems are monitored by management, and evaluated by an internal audit function that regularly reports its findings to management and the Audit Committee of the Board of Directors.

The consolidated financial statements have been examined by KPMG LLP, the Partnership's external auditors. The external auditors are responsible for examining the consolidated financial statements and expressing their opinion on the fairness of the financial statements in accordance with Canadian generally accepted accounting principles. The auditors' report outlines the scope of their audit examination and states their opinion.

The Board of Directors, through the Audit Committee, is responsible for ensuring management fulfills its responsibility for financial reporting and internal controls. The Audit Committee, which is comprised solely of independent directors, meets regularly with management, the internal auditors and the external auditors to satisfy itself that each group is discharging its responsibilities with respect to internal controls and financial reporting. The Audit Committee reviews the consolidated financial statements and recommends their approval to the Board of Directors. The external auditors have full and open access to the Audit Committee, with and without the presence of management.

On behalf of management,

Brian T. Vaasjo
President

Stuart A. Lee
Chief Financial Officer

March 6, 2006

AUDITORS' REPORT TO THE PARTNERS OF EPCOR POWER L.P.

We have audited the consolidated balance sheets of EPCOR Power L.P. as at December 31, 2005 and 2004 and the consolidated statements of income, cash flows and partners' equity for the years then ended. These financial statements are the responsibility of management of the General Partner. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by the General Partner's management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Edmonton, Canada

March 6, 2006

CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31	2005	2004
(millions of dollars except units and per unit amounts)		
Revenues	**295.7**	241.8
Cost of Fuel	**57.6**	53.8
Operating and Maintenance Expense	**27.9**	25.5
Other Plant Operating Expenses	**17.8**	12.7
Operating Margin	**192.4**	149.8
Other Costs		
Depreciation and amortization	**67.7**	55.0
Management and administration	**8.9**	6.9
Foreign exchange gains	**(6.4)**	(30.8)
Financial charges and other (Note 5)	**25.7**	14.1
	95.9	45.2
Net Income Before Income Tax	**96.5**	104.6
Income Taxes (Note 8)	**10.0**	3.9
Net Income	**86.5**	100.7
Net Income Per Unit	**$1.83**	$2.25
Weighted Average Units Outstanding (millions)	**47.4**	44.7

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOW

Years ended December 31 *(millions of dollars)*	**2005**	2004
Operating Activities		
Net income	**86.5**	100.7
Items not affecting cash:		
Depreciation and amortization	**67.7**	55.0
Future income tax	**5.0**	0.5
Unrealized foreign exchange gains	**(7.3)**	(31.9)
Other	**5.4**	3.9
Funds generated from operations	**157.3**	128.2
(Increase)/decrease in operating working capital	**(10.6)**	15.4
Cash provided by operating activities	**146.7**	143.6
Investing Activities		
Acquisition of Curtis Palmer and Manchief facilities (Note 13)	**–**	(576.8)
Acquisition of Mamquam and Queen Charlotte facilities (Note 14)	**–**	(152.5)
Additions to property, plant and equipment	**(14.4)**	(14.6)
Cash used in investing activities	**(14.4)**	(743.9)
Financing Activity		
Distributions paid	**(119.5)**	(109.3)
Repayment of TransCanada operating line	**–**	(26.0)
Credit facility issued	**–**	188.0
Credit facility repaid	**–**	(188.0)
Short-term U.S. dollar debt issued	**–**	529.9
Short-term U.S. dollar debt repaid	**–**	(524.6)
Long-term debt issued	**–**	465.2
Long-term debt repaid	**(0.8)**	–
Deferred financing costs	**–**	(5.3)
Limited partner units issued, net of costs	**–**	286.9
Cash provided by financing activities	**(120.3)**	616.8
Increase in Cash and Cash Equivalents	**12.0**	16.5
Cash and Cash Equivalents, Beginning of Year	**20.2**	3.7
Cash and Cash Equivalents, End of Year	**32.2**	20.2
Supplementary Cash Flow Information		
Income taxes paid	**2.3**	3.4
Interest paid	**25.2**	4.8

See accompanying notes to the consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

As at December 31	2005	2004
(millions of dollars)		
ASSETS		
Current Assets		
Cash and cash equivalents	**32.2**	20.2
Accounts receivable	**46.4**	27.3
Inventories	**7.2**	7.2
Prepaids and other	**4.3**	4.2
	90.1	58.9
Plant, Property and Equipment (Note 3)	**873.7**	902.4
Power Purchase Arrangements (Note 4)	**347.9**	371.4
Future Income Taxes (Note 8)	**–**	2.4
Other Assets	**4.6**	4.6
	1,316.3	1,339.7
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Accounts payable	**42.5**	28.0
Distributions payable	**29.9**	29.9
Long-term debt due within one year (Note 5)	**0.9**	0.8
	73.3	58.7
Asset Retirement Obligations (Note 9)	**17.1**	16.0
Long-Term Debt (Note 5)	**435.8**	444.4
Future Income Taxes (Note 8)	**2.5**	–
Partners' Equity	**787.6**	820.6
Commitments and Contingencies (Note 15)		
Subsequent Event (Note 16)		
	1,316.3	1,339.7

See accompanying notes to the consolidated financial statements

Approved by EPCOR Power Services Ltd., as General Partner of EPCOR Power L.P.

Donald J. Lowry
Director and
Chairman of the Board

Brian A. Felesky
Director and
Chairman of the Audit Committee

CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY

Years Ended December 31	**2005**	2004
(millions of dollars)		
Partnership Capital, beginning of year	**1,015.6**	728.7
Issue of Partnership Units (Note 6)	**–**	286.9
Partnership Capital, end of year	**1,015.6**	1,015.6
Accumulated Deficit, beginning of year	**(195.0)**	(181.3)
Net Income	**86.5**	100.7
Cash Distributions	**(119.5)**	(114.4)
Accumulated Deficit, end of year	**(228.0)**	(195.0)
Partners' Equity	**787.6**	820.6

See accompanying notes to the consolidated financial statements.

Note 1 – DESCRIPTION OF THE PARTNERSHIP

EPCOR Power L.P. (formerly TransCanada Power, L.P.) is a limited partnership created under the laws of the Province of Ontario pursuant to a Partnership Agreement dated March 27, 1997, as amended and restated August 31, 2005. EPCOR Power L.P. (the Partnership) commenced operations on June 18, 1997 and currently has independent power generating facilities in Ontario, British Columbia, New York and Colorado.

EPCOR Power Services Ltd., the General Partner, is an indirect wholly-owned subsidiary of EPCOR Utilities Inc., collectively with its subsidiaries, (EPCOR) and has the responsibility for overseeing the management of the Partnership and cash distributions to unitholders. The General Partner has engaged certain other EPCOR subsidiaries (collectively, the Manager) to perform management and administrative services on behalf of the Partnership and to operate and maintain the power plants pursuant to management and operations agreements.

Note 2 – SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements of the Partnership have been prepared by the management of the General Partner in accordance with Canadian generally accepted accounting principles (GAAP) and include the accounts of the Partnership and of its subsidiaries. All significant intercompany transactions and balances have been eliminated.

Measurement Uncertainty

The preparation of the Partnership's financial statements, in accordance with GAAP requires management to make estimates that affect the reported amounts of revenues, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Foreign Currency Translation

The Partnership indirectly owns United States subsidiaries, the accounts of which are integrated with those of the Partnership and translated into Canadian dollars using the temporal method. Under this method, monetary assets and liabilities are translated at the exchange rate in effect at the balance sheet date. Non-monetary assets and liabilities are translated at historic exchange rates. Revenues and expenses are translated at rates in effect at the time of the transactions. The resulting foreign exchange gains and losses are included in the consolidated statements of income.

Cash and Cash Equivalents

The Partnership's cash and cash equivalents include bank balances and short-term investments that have original maturities of three months or less. Short-term investments are recorded at cost, which approximates market value.

Inventories

Inventories of spare and replacement parts are carried at the lower of average cost and net realizable value.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Power generation plant and equipment, less estimated residual value, is depreciated on a straight-line basis over the estimated service life. Other equipment, which includes the costs of major overhauls, is capitalized and depreciated over estimated service lives of three to ten years.

On April 29, 2004, unitholders approved an amendment to the terms of the Partnership Agreement to remove the Partnership's obligation to redeem, in 2017, all of the units then outstanding not held directly by TransCanada. As a result of removing this redemption obligation, the Partnership prospectively changed its depreciation policy to depreciate power generation plant and equipment over its remaining useful life, whereas the previous policy was to depreciate these assets over their remaining life to 2017.

Property, plant and equipment, including asset retirement costs, are periodically reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable from estimated undiscounted future cash flows. If it is determined that the estimated net recoverable amount is less than the net carrying amount, a write-down to the asset's fair value is recognized during the period, with a charge to income.

Power Purchase Arrangements

Power purchase arrangements (PPAs) are long-term contracts to purchase power from the Partnership on a predetermined basis. The portion of the purchase price for the Curtis Palmer, Manchief, Mamquam and Queen Charlotte acquisitions which was allocated to PPAs is being amortized over the remaining terms of the contracts, which range from seven to twenty two years, from the dates of acquisition.

Deferred Debt Issue Costs

The Partnership incurred placement fees and other costs in connection with issuing long-term debt. These amounts are included in other assets and amortized over the term of the related debt.

Revenue Recognition

Revenue is recognized when energy is delivered under various long-term contracts. Revenue under the Curtis Palmer PPA is recognized at the lower of (1) the cumulative billable contract price per megawatt hour (MWh) and (2) an amount determined by the MWhs made available during the period multiplied by the average price per MWh over the term of the contract from the date of acquisition. Any excess of the contract price over the average price is recorded as deferred revenue.

Asset Retirement Obligations

The Partnership recognizes asset retirement obligations for the gas-fired and wood waste power plants. The fair value of the liability is added to the carrying value of the associated plant asset and depreciated accordingly. The liability is accreted at the end of each period through charges to operating expenses. No amount has been recorded for asset retirement obligations relating to the hydroelectric power plants as it is not possible to make a reasonable estimate of the fair value of the liability due to the indeterminate timing and scope of the retirements.

The Partnership has recorded these asset retirement obligations, as it is legally required to remove the facilities at the end of their useful lives and restore the plant sites to their original condition.

Income Taxes

Pursuant to the Income Tax Act (Canada) as presently enacted, the Partnership will not be subject to income taxes to the extent that its taxable income and taxable capital gains are paid or payable to unitholders. The Partnership is contractually committed to distribute to its unitholders all or virtually all of its taxable income and taxable capital gains that would otherwise be taxable to it. However, certain subsidiary corporations are taxable and applicable income, withholding and capital taxes have been reflected in these consolidated financial statements.

Future tax assets and liabilities are determined based on temporary differences between the tax basis of assets and liabilities of subsidiary corporations and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse.

Derivative Financial Instruments

The Partnership has established a hedging program to manage its exposure to changes in foreign currency exchange rates that result from future anticipated U.S. dollar-denominated cash flows from its U.S. power plants. The Partnership also hedges future anticipated interest payments on certain Canadian dollar-denominated long-term debt.

The fair values of the forward foreign exchange contracts and interest rate hedges are estimated using period-end forward market rates. These fair values approximate the amount that the Partnership would receive or pay if these instruments were closed out at the period-end dates. Gains or losses relating to these hedges are recognized in income in the same period and in the same financial statement category as the gains or losses on the corresponding hedged transactions.

A derivative must be designated and effective to be accounted for as a hedge. For cash flow hedges, effectiveness is achieved if the changes in the cash flows of the derivative substantially offset the changes in the cash flows of the hedged position and if the timing of the cash flows is similar. In the event that a derivative does not meet the designation or effectiveness criterion, the gain or loss on the derivative is recognized in income immediately. If a derivative that qualifies as a hedge is settled early, the gain or loss at settlement is deferred and recognized when the gain or loss on the designated transaction is recognized. Premiums paid or received with respect to derivatives that are hedges are deferred and amortized to income over the term of the hedge.

Net Income per Unit

Net income per unit is calculated by dividing net income by the weighted average number of units outstanding, including those held by EPCOR.

Note 3 – PLANT, PROPERTY AND EQUIPMENT

December 31 *(millions of dollars)*	**2005**			2004		
	Cost	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Land	**4.7**	**–**	**4.7**	4.7	–	4.7
Power generation plant and equipment	**1,082.9**	**245.5**	**837.4**	1,065.0	204.1	860.9
Asset retirement cost	**15.8**	**1.2**	**14.6**	15.5	0.5	15.0
Other equipment	**9.2**	**4.6**	**4.6**	7.7	3.6	4.1
Work in progress	**12.4**	**–**	**12.4**	17.7	–	17.7
	1,125.0	**251.3**	**873.7**	1,110.6	208.2	902.4

Depreciation expense with respect to the plant, property and equipment was $44.2 million for the year ended December 31, 2005 (2004 – $40.6 million).

Note 4 – POWER PURCHASE ARRANGEMENTS

December 31 *(millions of dollars)*	**2005**			2004		
	Cost	**Accumulated Amortization**	**Net Book Value**	Cost	Accumulated Amortization	Net Book Value
Power purchase arrangements	**385.8**	**37.9**	**347.9**	385.8	14.4	371.4

Amortization expense with respect to the PPAs was $23.5 million for the year ended December 31, 2005 (2004 – $14.4 million).

Note 5 – LONG-TERM DEBT

December 31 *(millions of dollars)*	**Interest Rate**	**2005**	Interest Rate	2004
Credit facility [(1)], due 2009	**3.3%**	**210.0**	3.2%	210.0
Secured term loan, due 2010	**11.3%**	**5.7**	11.3%	6.5
Unsecured senior notes (US$190.0 million), due 2014	**5.9%**	**221.0**	5.9%	228.7
		436.7		445.2
Less: Current portion of long-term debt		**0.9**		0.8
		435.8		444.4

(1) The all-in effective interest rate after consideration of forward contracts is approximately 5.1 per cent for the year ending December 31, 2005 (2004 – 5.2 per cent).

The $210.0 million credit facility is with a syndicate of Canadian banks and is non-amortizing. The outstanding principal is due in full upon maturity in November 2009. Under the terms of this credit facility, the Partnership can obtain advances by way of prime loans, US Base Rate loans, LIBOR loans and Bankers' Acceptances. At December 31, 2005, the loan bears interest at an average bankers' acceptance rate of 3.3 per cent (2004 – 3.2 per cent). The effective interest rate after including forward interest rate contracts is approximately 5.1 per cent (2004 – 5.2 per cent).

The secured term loan was secured by a first fixed and specific mortgage over the Queen Charlotte plant. The loan bears interest at an annual rate of approximately 11.3 per cent and matures on July 15, 2010.

The unsecured senior notes are the obligation of Curtis Palmer Inc., an indirect wholly-owned subsidiary of the Partnership. The notes are fully and unconditionally guaranteed as to payment of principal, premium, if any, and interest on a senior unsecured basis by the Partnership. The notes mature in July 2014. Interest on the notes accrues at 5.9 per cent per annum and is payable semi-annually in arrears commencing January 2005.

Principal Repayments

Principal repayments on the long-term debt of the Partnership for the next five years are estimated as follows:

(millions of dollars)	**Long-term debt**
2006	**0.9**
2007	**1.0**
2008	**1.1**
2009	**211.3**
2010	**1.4**
Later Years	**221.0**
Total Payments	**436.7**

Financial Charges and Other

Years ended December 31 *(millions of dollars)*	**2005**	2004
Interest on long-term debt	**25.3**	8.2
Interest on short-term debt	–	3.9
Other	**0.4**	2.0
	25.7	14.1

Note 6 – PARTNERS' EQUITY

December 31	**2005**		2004	
	Number of Units	**Millions of Dollars**	Number of Units	Millions of Dollars
Partnership capital, beginning of year	**47,421,982**	**1,015.6**	39,311,982	728.7
Issue of Partnership units	–	–	8,110,000	286.9
Partnership capital, end of year	**47,421,982**	**1,015.6**	47,421,982	1,015.6

The Partnership is authorized to issue an unlimited number of limited partnership units. Each unit represents an equal, undivided limited partnership interest in the Partnership and entitles the holder to participate equally in distributable cash and net income, except as noted below. Units are not subject to future calls or assessments and entitle the holder to limited liability. Each unit is transferable, subject to the requirements referred to in the Partnership Agreement.

In April 2004, the Partnership issued 8,110,000 subscription receipts, priced at $37.00 per subscription receipt, to the public and TransCanada for net proceeds of $286.9 million to finance part of the acquisition of the Curtis Palmer and Manchief facilities. On closing of the Curtis Palmer and Manchief acquisitions, each subscription receipt was exchanged for one limited partnership unit. In 2005, the weighted average number of units outstanding was 47,421,982 (2004 – 44,740,807).

Note 7 – FINANCIAL INSTRUMENTS

Fair Values of Financial Instruments

The carrying value of the current financial assets and liabilities recognized in the Consolidated Balance Sheets of the Partnership approximate their fair value due to their short period to maturity.

The following table summarizes estimated fair value information about the Partnership's financial instruments recognized in the Consolidated Balance Sheets that do not approximate fair value.

The estimated fair values of recognized financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

December 31 *(millions of dollars)*	**2005**		2004	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Unsecured senior notes (US$190.0 million)	**221.0**	**227.2**	228.7	237.9
Credit facility	**210.0**	**210.0**	210.0	210.0
Secured term loan	**5.7**	**6.7**	6.5	7.9

Derivative Financial Instruments

The Partnership is also a party to certain derivative financial instruments associated with financial risk management activities that are not recognized in the Consolidated Balance Sheets, as follows:

Foreign Exchange

The Partnership has cash flow exposure to changes in exchange rates on its operations denominated in U.S. dollars due to its investment in power plants in the United States.

As at December 31, 2005, outstanding forward foreign exchange contracts with a principal amount of US$93.5 million (2004 – US$88.5 million) had a positive fair value of $13.8 million (2004 – $13.2 million positive fair value). These contracts hedge a portion of the Partnership's future anticipated U.S. dollar-denominated cash flows from 2006 to 2011 at a weighted average exchange rate of 1.30.

Interest Rate

The Partnership periodically enters into interest rate swap contracts as part of its risk management strategy to manage its exposure to interest rates. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between the company and investment grade counterparties. The differentials of periodic interest payments are recognized in the accounts as an adjustment to interest expense.

As at December 31, 2005, outstanding interest rate swaps, which hedge the future interest payments from 2006 to 2009 on the Partnership's Canadian dollar credit facility, had a negative fair value of $5.2 million (2004 – $6.5 million negative fair value) and a notional principal amount of $200 million (2004 – $200 million).

Credit Risk

The electricity generated at the Partnership's facilities is sold under long-term contracts to five customers, Ontario Electricity Financial Corporation (OEFC), British Columbia Hydro and Power Authority (BC Hydro), TransCanada Power Marketing Inc., Niagara Mohawk Power Corporation (Niagara Mohawk) and Public Service Company of Colorado (PSCO). In 2005, approximately 50 per cent (2004 – 48 per cent) of revenues were earned from power sales to OEFC, 18 per cent (2004 – 17 per cent) from BC Hydro, and 18 per cent (2004 – 13 per cent) from Niagara Mohawk.

Note 8 – INCOME TAXES

The provision for income taxes in the consolidated financial statements differs from the result which would have been obtained by applying the combined Canadian federal and provincial tax rate to the Partnership's income before taxes. The difference results from the following:

RECONCILIATION OF INCOME TAX EXPENSE

Years ended December 31 *(millions of dollars)*	**2005**	2004
Income before taxes	**96.5**	104.6
Combined federal and provincial tax rate	**34.1%**	34.1%
Expected income tax expense	**32.9**	35.7
Income allocated to Partnership unitholders	**(24.9)**	(23.1)
Amounts related to foreign exchange	**(0.5)**	(9.7)
Withholding taxes	**1.6**	0.8
Higher effective foreign tax rates	**1.4**	0.4
Other	**(0.5)**	(0.2)
Actual income tax expense	**10.0**	3.9

FUTURE INCOME TAX ASSET

December 31 *(millions of dollars)*	**2005**	2004
Difference in accounting and tax basis of plant, equipment and PPAs	**–**	1.5
Deferred revenue and other	**2.4**	0.9
Future income tax assets	**2.4**	2.4

FUTURE INCOME TAX LIABILITY

December 31 *(millions of dollars)*	**2005**	2004
Difference in accounting and tax basis of plant, equipment and PPAs	**4.4**	–
Other	**0.5**	–
Future income tax liability	**4.9**	–
Net Future Income Tax (Liability)/Asset	**(2.5)**	2.4

Canadian based corporate subsidiaries of the Partnership are subject to tax on their taxable income at a rate of approximately 34 per cent (2004 – 34 per cent) while US corporate subsidiaries are subject to tax on their taxable income at rates varying from 38 to 41 per cent (2004 – 38 to 41 per cent). The tax effects of temporary differences relating to corporate subsidiaries have been reflected in these consolidated financial statements with the exception of $1.0 million (2004 – $1.0 million) of non-capital losses in a Canadian corporate subsidiary which the Partnership does not believe will be utilized prior to their expiration in 2010 and 2011.

Taxable income of the Partnership and its subsidiary limited partnerships will be taxed in the hands of unitholders. The Partnership and its Canadian subsidiary limited partnerships have net taxable temporary differences of $366.0 million (2004 – $376.8 million) which are not reflected in these financial statements.

Note 9 – ASSET RETIREMENT OBLIGATIONS

December 31 *(millions of dollars)*	**2005**	2004
Asset retirement obligations, beginning of year	**16.0**	–
Liabilities incurred	**0.2**	15.5
Accretion of asset retirement obligations	**0.9**	0.5
Asset retirement obligations, end of period	**17.1**	16.0

At December 31, 2005, the estimated cost to settle the Partnership's asset retirement obligations was $65.0 million (2004 – $66.1 million) calculated using an inflation rate of 3.0 per cent per annum (2004 – 3.0 per cent). The estimated cash flows were discounted at 6.6 per cent (2004 – 6.6 per cent). At December 31, 2005, the expected timing of payment for settlement of the obligations ranges from three to thirty five years.

Note 10 – RELATED PARTY TRANSACTIONS

Amounts charged to the Partnership under these and other contracts with EPCOR (or TransCanada for the applicable periods) were as follows:

Years ended December 31 *(millions of dollars)*	**2005**	2004
Revenues		
Castleton – capacity payments [(1)]	**9.8**	15.3
Ontario – enhancement revenues	**19.9**	11.4
Ontario – gas diversion sales	**13.4**	10.3
Ontario – Calstock guarantee fee [(1)]	**2.1**	3.1
	45.2	40.1
Cost of Fuel		
Ontario – gas fuel supply [(1)]	**14.9**	20.9
Ontario – gas transportation [(1)]	**7.5**	12.0
Ontario – waste heat [(1)]	**0.4**	0.7
Castleton – gas demand charge	**2.3**	2.4
	25.1	36.0
Operating and Maintenance Expense	**27.8**	25.5
Management and Administration		
Base fee	**1.2**	1.1
Incentive fee	**2.0**	1.9
Enhancement fee	**2.9**	1.3
	6.1	4.3
Acquisition Fees	**–**	8.7
Interest Expense		
Operating line	**–**	0.9
Promissory notes	**–**	0.7
	–	1.6

(1) These transactions were related party transactions up until September 1, 2005 at which time TransCanada sold its interest in the Partnership to EPCOR

Capacity Payments

The Partnership and TransCanada have an agreement expiring in 2008 whereby the Partnership provides to TransCanada the operating capacity and power output of the Castleton power plant in return for a fixed monthly fee, denominated in U.S. dollars, Castleton power plant in return for a fixed monthly fee, denominated in U.S. dollars.[1]

Enhancement Transactions

Gas sales are included in revenue related to enhancement transactions undertaken by the Manager at the Ontario power plants to re-sell contracted natural gas at high market prices, rather than produce off-peak power at lower rates. The Manager is entitled to receive an enhancement fee for each enhancement transaction equivalent to 35 per cent of the incremental profit.

Gas Diversion Sales

The Manager manages gas fuel supply on behalf of the Partnership and fuel in excess of daily plant requirements is sold on the open market through the Manager and is recorded as gas diversion sales.

Guarantee Fee

TransCanada provided a guarantee for a certain minimum annual cash flow for the Calstock plant from the year the Partnership acquired the plant until October 2005. [1]

Gas Fuel Supply

Fuel contracts include long-term agreements with the Manager to supply fuel for the North Bay and Kapuskasing plants.[1]

Gas Transportation and Waste Heat

The Partnership has long-term agreements with TransCanada to supply gas transportation and waste heat for each of the Ontario facilities.[1]

Operating and Maintenance

The Manager is entitled to receive a fee for services related to the operation and maintenance of the power plants under the Management and Operations Agreements. The annual fees are payable on an equal monthly basis and are adjusted annually with changes to the Consumer Price Index.

Base and Incentive Fee

The Manager is also entitled to a base fee and an incentive fee under Management and Operations Agreements in each fiscal year of the Partnership. The base fee is equal to one per cent of the Partnership's annual cash distributions. The incentive fee is equal to 20 per cent of annual cash distributions which exceed $2.31 per unit and are less than $2.52 per unit; and 30 per cent of annual cash distributions in excess of $2.51 per unit.

Promissory Notes

In April 2004, the Partnership issued US$192.6 million in promissory notes to TransCanada to temporarily fund the acquisition of Curtis Palmer and Manchief. The promissory notes were repaid in May 2004 with the proceeds from an acquisition facility which was subsequently repaid with proceeds from U.S. senior unsecured notes issued in June 2004 and cash on hand. [1]

Included in accounts payable at December 31, 2005 are amounts owing to EPCOR of $10.9 million.

Note 11 – OPERATING LEASES

From the point of view of a lessor, the terms of the Manchief, Mamquam and Queen Charlotte PPAs are operating leases. At December 31, 2005, the carrying value of the Manchief, Mamquam and Queen Charlotte plant, property and equipment was $233.1 million less accumulated depreciation of $10.7 million (2004 – $231.9 million and $3.9 million respectively). The Partnership's revenues for the year ended December 31, 2005 include $41.1 million with respect to the Manchief, Mamquam and Queen Charlotte PPAs (2004 – $22.5 million).

Note 12 – U.S. OPERATIONS

For the year ended December 31, 2005, the Partnership's U.S. operations generated approximately $91.5 million of revenue (2004 – $64.9 million). At December 31, 2005 the net book value of U.S. plant, property and equipment and PPAs was $553.8 million (December 31, 2004 – $586.1 million).

Note 13 – ACQUISITION OF CURTIS PALMER AND MANCHIEF FACILITIES

On April 30, 2004, the Partnership acquired, from TransCanada, 100 per cent of the entities which own the Curtis Palmer and Manchief power plants for consideration of US$402.6 million ($551.8 million), plus post-closing adjustments of $17.1 million and acquisition costs of $7.9 million. Acquisition costs included fees of $5.8 million paid to TransCanada, pursuant to the Transaction Fees and Costs Agreement existing at that time, and legal and advisory fees of $2.1 million. The purchase price of $576.8 million was allocated using an estimate of fair values of the net assets at the date of acquisition as follows:

(millions of dollars)	**Curtis Palmer**	**Manchief**	**Total**
Current assets	7.0	4.7	11.7
Plant, property and equipment	115.4	119.5	234.9
PPAs	263.8	68.7	332.5
Current liabilities	(0.3)	(0.5)	(0.8)
Asset retirement obligations	–	(1.5)	(1.5)
	385.9	190.9	576.8

(1) These transactions were related party transactions up until September 1, 2005 at which time TransCanada sold its interest in the Partnership to EPCOR.

The Partnership entered into an agreement with the Manager to operate and manage the Curtis Palmer and Manchief power plants at an annual fee of approximately $5.1 million, adjusted annually for inflation.

Note 14 – ACQUISITION OF QUEEN CHARLOTTE AND MAMQUAM FACILITIES

On July 23, 2004, the Partnership acquired companies that indirectly owned Hydro Investment Corporation (HIC) for approximately $151.9 million, net of $9.1 million of cash acquired on closing. The purchase price included post-closing adjustments of approximately $2.6 million and acquisition costs of $5.0 million. Acquisition costs include fees of $2.9 million paid to TransCanada, pursuant to the Transaction Fees and Costs Agreement existing at that time, and legal and advisory fees of $2.1 million. Through the acquisition, the Partnership obtained ownership of two hydroelectric facilities in British Columbia, the Mamquam and Queen Charlotte power plants, which were owned by subsidiaries of HIC. The total purchase price of $161.0 million was allocated based on an estimated fair value of the assets and liabilities acquired as follows:

(millions of dollars)	
Cash	9.1
Other current assets	0.5
Plant, property and equipment	105.0
PPAs	53.2
Current liabilities	(0.3)
Long-term debt due within one year	(0.8)
Long-term debt	(5.7)
	161.0

The Manager operates and manages the Mamquam and Queen Charlotte power plants at an annual fee of approximately $1.2 million, adjusted for inflation.

Note 15 – COMMITMENTS AND CONTINGENCIES

Operating Commitments

The Ontario plants are under fixed long-term gas supply contracts, gas transportation contracts and waste heat supply contracts with built-in annual escalators. Expiry dates for the contracts vary in length with an average remaining contract life of nine years as at December 31, 2005. The remaining fuel requirements, which account for approximately five per cent of the power plants' fuel costs, are purchased at current market prices.

As of December 31, 2005 the Partnership's future purchase obligations were estimated as follows, based on existing contract terms, estimated inflation and expected volumes of waste heat based on historical patterns.

(millions of dollars)	**Gas Supply Contracts**	**Gas Transportation Contracts**	**Waste Heat Supply Contracts**
2006	34.5	12.5	0.8
2007	38.6	13.2	0.8
2008	43.8	14.0	0.8
2009	45.9	14.9	0.9
2010	46.0	15.0	0.9
Later years	299.8	110.3	5.4
Total payments	508.6	179.9	9.6

Contingencies

In July 2004, NAL Resources Limited ("NAL") and Devon Canada Corporation ("Devon") commenced actions against the Partnership claiming the gas supply contracts under which NAL and Devon sell gas to the Partnership for its Tunis, Ontario power plant have been frustrated as of January 1, 2003 due to an alleged inability to determine the commodity charge for gas under such agreements. NAL and Devon additionally seek monetary damages based on referenced spot gas prices should the courts uphold their claims.

The Partnership has filed statements of defence and intends to vigorously defend the actions. The final outcome is not determinable and accordingly, no amount has been accrued in the financial statements.

Note 16 – SUBSEQUENT EVENT

On March 6, 2006, the Partnership reached an agreement with O.E.F.C. on a replacement for the Direct Customer Rate ("DCR") index that was discontinued in 2002. The index is used in the PPAs for the five facilities in Ontario to determine the annual increase in the price of power. This settlement adjusts the amount owed under these PPAs for the period from 2002 through the end of 2005 as well as replacing the DCR index prospectively to the end of the respective PPAs. Management estimates the retroactive portion of the settlement for the periods from 2002 to the end of 2005 will have a positive net income impact of approximately $8 million which will be recorded in the first quarter of 2006.

Note 17 – COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current year's presentation.

Partnership Governance

The governance of the Partnership is the responsibility of the Board of Directors (the Board) of the General Partner and the rights, authority and limitations on the General Partner are described in the Limited Partnership Agreement (the Partnership Agreement). The Partnership Agreement contemplates that the Board will be composed of seven directors, four of which are related to EPCOR with the remaining three members being unrelated to, independent of any relationship, whether direct or indirect, with, EPCOR.

The Board has, however, determined that it is appropriate and in the interests of good governance that an additional independent and unrelated director be appointed to the Partnership's Board. This has resulted in the Board of Directors consisting of eight directors, four of whom are independent of and unrelated to EPCOR and four who are related to EPCOR. Additionally, the Audit Committee is composed solely of independent directors in compliance with the Audit Committee rules under Multilateral Instrument 52-110 and the majority of members of the Partnership's Corporate Governance Committee are independent. The Board has also determined that the independent directors would designate a "Lead Director" from among their number to assist in ensuring the independent functioning of the Board.

The Board has plenary power over all activities of the Partnership unless specifically delegated to committees of the Board or management. To fulfill its responsibilities, the Board has therefore established three committees: Audit, Corporate Governance and Independent Directors.

The Partnership Agreement provides that the Board can function separately from the Manager and management, as a majority of independent directors must approve all material transactions or agreements between the Partnership and EPCOR or any of its affiliates. The Board's governance structure has accommodated this requirement through the establishment of the Independent Directors Committee, which recommends all material transactions between the Partnership and EPCOR or any of EPCOR's affiliates to the Board. Moreover, whenever the Board is required to approve any transaction between the Partnership and EPCOR or any of EPCOR's affiliates, the EPCOR-elect Directors recuse themselves from Board discussions and any vote on such transactions is held solely amongst the independent directors.

Both the Board and its committees can approve the engagement of outside advisors. The engagement of advisors for the committees or individual members is limited to advisors required for matters within a committee's mandated responsibilities or for advice relative to a member's fiduciary duties or conflict of interest matters.

As a publicly traded entity, the Partnership is required to disclose annually its alignment with a set of corporate governance rules and guidelines adopted by Canadian securities regulatory authorities to assist in assessing accountability to stakeholders. The Partnership's statement on adherence to those rules and guidelines follows.

1 Board should explicitly assume responsibility for stewardship of the Partnership

Does the Partnership Align? Yes

Description of Approach The Board has oversight over the management of the Partnership, establishing the material policies and standards employed by the Partnership in the operation of its businesses, approving its strategic plans and reviewing its progress toward achievement of those plans.

2 Adoption of a strategic planning process

Does the Partnership Align? Yes

Description of Approach The Board has adopted a strategic planning process and meets during the year to review and approve management's strategic plan for the Partnership. Changes to the plan assumptions are considered when appropriate.

3 Identification of principal business risks, and implementation of risk management systems

Does the Partnership Align? Yes

Description of Approach The strategic plan process adopted by the Board also includes the review of significant risks to the Partnership and management ensures that the Board is kept informed of any changes to these risks on a timely basis.

The Audit Committee reviews the Partnership's financial and business risks and related policies and procedures and reports to the Board in respect thereto on a quarterly basis. The Board also receives and reviews reports from management regarding stewardship of health, safety and environmental matters pertaining to Partnership business on a regular basis.

4 Succession planning, including appointment, training and monitoring senior management

Does the Partnership Align? No

Description of Approach Under the terms of the Management and Operations Agreements, the Manager is responsible to fill the required management positions. The Board believes, however, that management of the Partnership is key to its ongoing success, so the Partnership's Corporate Governance Committee reviews the Manager's key policies and procedures regarding management succession, training, compensation and appointment.

5 A communications policy

Does the Partnership Align? Yes

Description of Approach The Board has put structures in place that seek to ensure effective communications between the Partnership, its unitholders and the public. The Board and/or the Audit Committee review the content of the Partnership's major communications to the investing public (including the quarterly and annual filings), and approve the Annual Information Form and any prospectuses that may be issued. The disclosed information is released through mailings to unitholders, news wire services, the general media and the Partnership's website.

6 Integrity of internal control and management information systems

Does the Partnership Align? Yes

Description of Approach The Partnership's internal controls are monitored on a regular basis by the Audit Committee and the work of the internal audit department of EPCOR.

7 Majority of directors should be "unrelated" (independent from management and free from conflicts of interest)

Does the Partnership Align? No

Description of Approach EPCOR has the right to nominate four of the seven directors under the terms of the Partnership Agreement. Notwithstanding this right, the Board unanimously determined that an additional independent director should be appointed and has therefore fixed the size of the Board to eight directors. In addition, the Chair of the Board (who is an EPCOR-elect Director) has a casting vote. Non-EPCOR unitholders are, however, protected by the fact that the Audit and Independent Directors Committee are comprised solely of independent directors and these two Committees are solely responsible for overseeing and approving non-arm's length dealings between EPCOR and the Partnership. The Board has also appointed a Lead Director whose responsibility it is to ensure the Board can function independently from management, that appropriate communication links exist between the independent directors and the Partnership's senior management, and to chair meetings of the Board in the absence of the EPCOR-elect Chair. The Board therefore believes that this structure is appropriate for the Partnership given the relationship between EPCOR and the Board and EPCOR's substantial ownership of Partnership Units.

8 Disclose for each director whether he or she is related, and how that conclusion was reached and that the majority of directors are 'outside' directors

Does the Partnership Align? No

Description of Approach The Board has four unrelated directors and four related directors. The independent directors are Messrs. B. Felesky, A. Hagerman, E. Hobson and R. Wimer and the four related directors are Messrs. D. Lowry, M. Wiltzen, B. Vaasjo and D. Topping, all of whom are senior officers of EPCOR.

9 Appoint a committee of outside directors responsible for appointment of new nominees and ongoing assessment of directors

Does the Partnership Align? No

Description of Approach A subcommittee of the Corporate Governance Committee composed of independent directors is responsible for assessing and recommending new nominees to the Board. The Corporate Governance Committee, as a whole, is responsible for assessing on an annual basis the Board performance, and periodically the performance of each member. The committee is chaired by Mr. E. Hobson, an independent director and is composed of a majority of independent directors.

10 Implement a committee process for assessing the effectiveness of the Board, its committees and the contribution of individual directors

Does the Partnership Align? Yes

Description of Approach The Corporate Governance Committee is responsible to make an annual assessment of the overall performance of the Board and each of its committees and a periodic assessment of the performance of individual directors. The Corporate Governance Committee reports its findings to the Board. The Corporate Governance Committee also makes recommendations relative to the composition of the various committees of the Board.

11 Provide orientation and education programs for new recruits to the Board

Does the Partnership Align? Yes

Description of Approach All directors are provided with an orientation binder that includes written information about the duties and obligations of directors and the business of the Partnership. An orientation training session with the President and Corporate Secretary, as well as an opportunity for meetings and discussions with senior management and other directors are also provided. The Partnership funds 50% of a directors' attendance at educational programs and seminars which cover various subjects directly related to the duties and responsibilities of directors.

12 Examine size of Board, with a view to improving effective decision-making and, if appropriate, undertake a program to reduce the number of directors

Does the Partnership Align? Yes

Description of Approach The Board believes that eight directors is appropriate and is the minimum number required to effectively oversee the business of the Partnership.

13 Review adequacy and form of compensation of directors to ensure compensation reflects risks and responsibilities

Does the Partnership Align? Yes

Description of Approach The Corporate Governance Committee reviews the compensation of the independent directors on an annual basis, taking into account such matters as time commitment, responsibility and compensation provided by comparable companies and income funds. No director related to EPCOR receives compensation from the Partnership for services to the Board or committees.

14 Committees should generally be composed of outside directors a majority of which are unrelated

Does the Partnership Align? Yes

Description of Approach The Board believes that, as a matter of policy, there should be a majority of unrelated directors on each of the committees and the committees should be chaired by independent directors. The Audit Committee and the Independent Directors Committee are composed solely of independent directors while one member (a minority) of the Corporate Governance Committee is related to EPCOR.

15 Appoint a committee responsible for developing an approach to corporate governance issues

Does the Partnership Align? Yes

Description of Approach The mandate of the Corporate Governance Committee includes responsibility to undertake initiatives as are needed to ensure excellence in governance.

16 Define limits to management's responsibilities by developing position descriptions for the Board and CEO and approving corporate objectives for the CEO to meet

Does the Partnership Align? Yes

Description of Approach The Board has adopted its own terms of reference, which clarify responsibilities and ensure effective communication between the Board and management. The Corporate Governance Committee also recommends position descriptions for the President and senior officers of the General Partner. Under the contractual agreements with the Manager, filling the positions is the responsibility of the Manager, who discharges this responsibility in consultation with the Corporate Governance Committee and the Board.

17 Establish procedures to enable the Board to function independently of management

Does the Partnership Align? Yes

Description of Approach The Partnership Agreement provides that the Board can function separately from the Manager and management of the General Partner, as a majority of independent directors must approve all material transactions or agreements between the Partnership and EPCOR or any of its affiliates. The Board has also appointed a Lead Director whose responsibility it is to ensure the Board can function independently from management, that appropriate communication links exist between the independent directors and the Partnership's senior management, and to chair meetings of the Board in the absence of the EPCOR-elect Chair.

18 Establish an Audit Committee composed only of outside directors with specifically defined roles and responsibilities

Does the Partnership Align? Yes

Description of Approach The Audit Committee for the Partnership has defined roles and responsibilities as outlined in its charter. The committee is composed of independent and unrelated directors and is in compliance with the Audit Committee rules under Multilateral Instrument 52-110.

19 Implement a system to enable individual directors to engage outside advisors at the corporation's expense

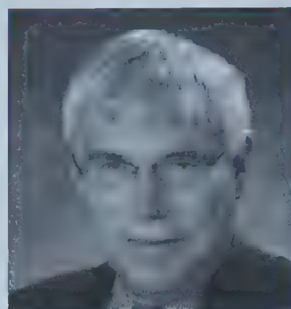
Does the Partnership Align? Yes

Description of Approach Independent directors have the authority to retain consultants for themselves or the Independent Directors Committee where necessary and appropriate.

Board of Directors

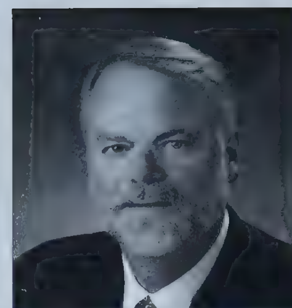
Brian A. Felesky, C.M., Q.C.
Partner, Felesky Flynn
Calgary, Alberta

- Chair, Audit Committee
- Independent Directors Committee



Allen R. Hagerman, F.C.A.
Chief Financial Officer,
Canadian Oil Sands Limited
Calgary, Alberta

- Chair, Independent Directors Committee
- Vice Chair, Audit Committee
- Corporate Governance Committee



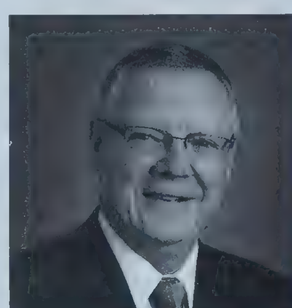
Eric Hobson
Partner, Northridge Canada
Calgary, Alberta

- Lead Director
- Chair, Corporate Governance Committee
- Audit Committee
- Independent Directors Committee

Rod Wimer
Managing Director,
Mazama Capital Partners, LLC
Bend, Oregon

- Independent Directors Committee

Donald J. Lowry
Chairman,
EPCOR Power Services Limited
President & CEO,
EPCOR Utilities Inc.
Edmonton, Alberta



Douglas R. Topping
Senior Vice President,
EPCOR Power Development Corporation
Edmonton, Alberta

Brian T. Vaasjo
President,
EPCOR Power Services Limited
Executive Vice President,
EPCOR Utilities Inc.
Edmonton, Alberta

- Corporate Governance Committee

Mark D. Wiltzen
Senior Vice President &
Chief Financial Officer
EPCOR Utilities Inc.
Edmonton, Alberta

Officers

Brian Vaasjo, President
Jim Fitzowich, Vice President, Commercial Services
Kate Chisholm, Vice President, General Counsel, Corporate Secretary
Stephen Muir, Vice President & Treasurer
Stuart Lee, Chief Financial Officer
Sandra Haskins, Controller
Bill Wright, Assistant Corporate Secretary

NINE-YEAR FINANCIAL HIGHLIGHTS

(millions of dollars except per unit amounts and operational information)	**2005**	2004	2003	2002	2001	2000	1999	1998	1997
Operational Information									
Number of plants	**11**	11	7	7	7	7	7	5	3
Weighted average plant availability	**94%**	97%	96%	94%	97%	99%	94%	97%	97%
Plant output (GWh)	**2,698**	2,419	2,153	2,417	2,358	2,291	1,560	1,273	521
Revenues	**295.7**	241.8	185.8	180.7	183.0	160.4	110.6	84.3	34.0
Operating Margin [1]									
Ontario	**82.8**	74.4	75.0	69.7	69.2	64.2	57.4	49.8	20.4
Williams Lake	**23.6**	23.9	25.4	28.0	33.2	24.6	2.9	–	–
Mamquam and Queen Charlotte	**10.7**	3.4	–	–	–	–	–	–	–
Curtis Palmer	**47.1**	26.9	–	–	–	–	–	–	–
Manchief	**20.2**	13.0	–	–	–	–	–	–	–
Castleton	**8.0**	8.2	8.8	9.9	9.3	8.1	4.0	–	–
	192.4	149.8	109.2	107.6	111.7	96.9	64.3	49.8	20.4
Net Income	**86.5**	100.7	64.4	64.1	45.0	46.0	37.5	34.6	15.0
Per unit	**$1.83**	$2.25	$1.64	$1.63	$1.28	$1.52	$1.48	$1.52	$0.79
Cash Flow									
Funds generated from operations	**157.3**	128.2	99.6	101.0	94.5	79.5	58.7	48.6	19.7
Per unit	**$3.32**	$2.87	$2.53	$2.57	$2.69	$2.62	$2.32	$2.13	$1.03
Capital expenditures	**(14.4)**	(14.6)	(8.2)	(5.4)	(11.6)	(6.8)	(9.7)	(13.8)	(2.0)
Acquisitions	**–**	(729.3)	–	–	–	–	(110.5)	(129.2)	–
Cash Distributions	**119.5**	114.4	99.1	99.1	87.4	72.8	59.3	49.0	21.2
Per unit	**$2.52**	$2.52	$2.52	$2.52	$2.49	$2.40	$2.34	$2.15	$1.11
Cash Available for Distributions	**142.1**	113.6	91.4	95.6	82.9	72.6	49.0	34.8	17.7
Per unit	**$3.00**	$2.54	$2.33	$2.43	$2.36	$2.40	$1.94	$1.53	$0.93
Balance Sheet									
Plant, property and equipment	**873.7**	902.4	573.5	601.4	633.2	658.6	656.7	336.9	178.2
Power purchase arrangements	**347.9**	371.4	–	–	–	–	–	–	–
Total assets	**1,316.3**	1,339.7	604.7	650.5	677.3	697.4	696.3	354.3	197.8
Long-term debt	**436.7**	445.2	–	–	–	159.4	165.7	–	–
Units Outstanding									
Weighted average for the year	**47.4**	44.7	39.3	39.3	35.1	30.3	25.3	22.8	19.1
Unit Prices on the TSX									
High	**$37.47**	$38.00	$37.10	$34.13	$32.05	$28.70	$29.40	$30.00	$30.20
Low	**$29.41**	$29.62	$30.80	$28.75	$27.00	$20.00	$21.40	$23.95	$27.15
Close	**$35.25**	$35.50	$36.30	$30.90	$31.75	$27.50	$24.50	$28.15	$28.10

(1) Operating Margin equals Revenues less Cost of Fuel, Operating and Maintenance Expenses and Other Plant Operating Expenses.
Note: Certain comparative financial information has been reclassified to conform with the 2005 presentation.

INVESTOR INFORMATION

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Toronto, ON M5C 2W9
Phone: 1-800-387-0825 (toll-free)
Facsimile: (416) 643-5501
E-mail: inquiries@cibcmellon.com
Web site: www.cibcmellon.com

Ownership Advisory – Units of the Partnership may only be held by residents of Canada. In the event that any units are acquired by a non-resident of Canada, the General Partner has the authority to take any steps necessary to ensure that such units are transferred to a resident of Canada.

STABILITY AND CREDIT RATINGS (as of December 31, 2005)

	Stability Ratings	Credit Ratings
Standard & Poor's Ratings Services (S&P)	SR-1	A-
Dominion Bond Rating Service (DBRS)	STA-1 (low)	A (low)

Auditors: KPMG LLP, Edmonton, Alberta
Stock Exchange: Toronto Stock Exchange (TSX)
Ticker Symbol: EP.UN
Total Outstanding Units: 47,421,982 (as of December 31, 2005)

2006 EXPECTED DISTRIBUTION DATES

	Ex-dividend date	Record date	Payment date
Quarter 1	March 29	March 31	April 28
Quarter 2	June 28	June 30	July 28
Quarter 3	September 27	September 29	October 30
Quarter 4	December 27	December 29	January, 2007

2005 UNIT PRICES AND VOLUMES

C$ except volume and units	2005	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
High	$37.47	$37.00	$37.47	$37.06	$35.90
Low	$29.41	$29.41	$34.75	$33.15	$31.60
Close	$35.25	$35.25	$35.99	$36.60	$33.60
Volume (millions)	16.3	5.4	3.7	3.7	3.5
Weighted average number of outstanding units (in millions)	47.4	47.4	47.4	47.4	47.4

Mission Statement

Our mission is to be Canada's premier income fund, providing a growing, stable cash distribution to our unitholders. We will accomplish this by being growth-oriented while providing our unitholders with reliable long-term cash flows. We will apply superior operating and commercial management practices to a quality portfolio of energy assets.

For more information, please contact:

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